PB87-168670

Evaluation of Sulfur Capture Capability of a Prototype Scale Controlled-Flow/Split-Flame Burner

Foster Wheeler Energy Corp., Livingston, NJ

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

Jan 87

U.S. Department of Commerce
National Technical Information Service
NTIS

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA/600/7-87/003	2.	3. RECIPIENT'S ACCESSION NO. PB87 - 168670/AS
4. TITLE AND SUBTITLE Evaluation of Sulfur Capture Capability of a Prototype Scale Controlled-Flow/Split-Flame Burner		5. REPORT DATE January 1987 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) J. Vatsky and E.S. Schindler		8. PERFORMING ORGANIZATION REPORT NO. 5-E-3
9. PERFORMING ORGANIZATION NAME AND ADDRESS Foster Wheeler Energy Corporation 110 S. Orange Avenue Livingston, New Jersey 07039		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-02-3906
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Air and Energy Engineering Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 9/82 - 2/84 14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES AEERL [illegible]oject officer is Charles C. Masser, Mail Drop 63, 919/541-7586.

16. ABSTRACT The report descr[illegible] sulfur capture potential during combustion of limestone copulverized with a [illegible]gh sulfur eastern bituminous coal, using Foster Wheeler's commercial Controlled-Flow/Split-Flame (CF/SF) low NOx, internally staged burner. Sulfur capture was optimized by using overfire air and two proprietary flame temperature control methods. Additionally, the effects of excess air changes, load changes, and different calcium/sulfur mole ratios (Ca/S) were evaluated. Two flame temperature reduction methods were used to reduce the flame temperature to minimize dead burning of limestone and thus enhance SO2 capture. Although the use of flame temperature reduction and overfire air improved the SO2 capture, the optimum SO2 capture of 29% at a Ca/S of 2.15 was low. Operation under optimum SO2 capture mode resulted in measured NOx emissions of 0.19 lb/million Btu; CO was less than 25 ppm at an excess oxygen level of 3.0%. The testing was done at a 42 million Btu/hr heat input horizontally fired pilot plant configured like a conventional pulverized-coal-fired boiler.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Burners	Pollution Control	13B	13A
Sulfur Dioxide	Flames	Stationary Sources	07B	
Nitrogen Oxides	Temperature	Sulfur Capture		14G
Limestone	Temperature Control	Overfire Air	08G	14B
Bituminous Coal			21D	
Combustion			21B	

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 192
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

PB87-168670

EPA/600/7-87/003
January 1987

EVALUATION OF SULFUR CAPTURE CAPABILITY OF A PROTOTYPE SCALE CONTROLLED-FLOW/SPLIT-FLAME BURNER

BY:

J. VATSKY AND E. S. SCHINDLER
FOSTER WHEELER ENERGY CORPORATION
LIVINGSTON, NEW JERSEY 07039

CONTRACT NO. 68-02-3906

EPA PROJECT OFFICER
CHARLES C. MASSER
AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
U. S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NORTH CAROLINA 27711

AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

REPRODUCED BY
U.S. DEPARTMENT OF COMMERCE
NATIONAL TECHNICAL
INFORMATION SERVICE
SPRINGFIELD, VA 22161

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

ABSTRACT

This report describes the sulfur capture potential during combustion of limestone copulverized with a high sulfur eastern bituminous coal. Foster Wheeler's commercial design Controlled Flow/Split Flame low NO_x, internally staged burner was utilized. Optimization of the sulfur capture through the use of overfire air and two proprietary flame temperature control methods was obtained. Additionally, the effects of excess air changes, load changes, and different calcium/sulfur mole ratios were evaluated. Two flame temperature reduction methods were utilized to reduce the flame temperature to minimize dead burning of limestone and thus enhance SO_2 capture. Although the use of flame temperature reduction and overfire air did improve the SO_2 capture, the optimum SO_2 capture of 29% at a calcium to sulfur mole ratio of 2.15 was low. Operation under optimum SO_2 capture mode resulted in measured NO_x emissions of 0.19 lb/10^6 Btu,* carbon monoxide was less than 25 ppm at an excess oxygen level of 3.0%. The testing was done at a 42 x 10^6 Btu/hr heat input horizontally fired pilot plant configured like a conventional pulverized coal fired boiler.

---

* Readers more familiar with metric units may use the factors listed at the end of the front matter to convert to that system.

TABLE OF CONTENTS

PAGE NO.

ABSTRACT iii
ILLUSTRATIONS vi
TABLES viii
LIST OF ABBREVIATIONS AND SYMBOLS ix
CONVERSION FACTORS ix

1. Introduction 1
2. Conclusions 3
3. Background 7
4. Test Results 14
5. Comparison of Results with 1980 Tests 77
6. Test Laboratory Description 82
7. Laboratory Equipment, Quality Assurance and Measurement Methods 92
8. Application to Full Scale 104

REFERENCES
APPENDICES 105

APPENDIX A: Test Results A-1
APPENDIX B: Coal and Sorbent Selection B-1
APPENDIX C: Quality Assurance Plan C-1

Preceding page blank

LIST OF ILLUSTRATIONS

Figure No.	Description	Page No.
3.1	Arch-Fired Boiler	8
3.2	Experimental Distributed Mixing Burner	10
3.3	Controlled Flow Split-Flame Burner	12
4.1	Variation in the Fuel Used at Aioi	16
4.2	Effect of Load and Limestone on SO_2 Reduction	19
4.3	Comparison of the Effect of Lower and Upper Overfire Airports	20
4.4	Effect of Excess Oxygen and Limestone on SO_2 Reduction	21
4.5	Effect of Excess Oxygen and Limestone on Sulfur Trioxide	23
4.6	Effect of Excess Oxygen and Limestone on NOx	24
4.7	Effect of Excess Oxygen and Limestone on Carbon Monoxide	26
4.8	Effect of Excess Oxygen and Limestone on Total Hydrocarbons	27
4.9	Effect of Excess Oxygen and Limestone on Peak Flame Temperature	29
4.10	Effect of Overfire Air and Limestone on Sulfur Dioxide Concentrations	31
4.11	Effect of Overfire Air and Limestone on Sulfur Trioxide Concentrations	32
4.12	Effect of Overfire and Limestone on NOx	34
4.13	Effect of Overfire Air and Limestone on Carbon Monoxide	36
4.14	Effect of Overfire Air and Limestone on Total Hydrocarbons	38
4.15	Effect of Overfire Air and Limestone on Peak Flame Temperature	40
4.16	Effect of Flame Temperature Reduction Method #1 and Limestone on Sulfur Dioxide Reduction	42
4.17	Effect of Flame Temperature Reduction Method #1 and Limestone on Sulfur Trioxide	43
4.18	Effect of Flame Temperature Reduction Method #1 and Limestone on NOx	45

LIST OF ILLUSTRATIONS
(Continued)

Figure No.	Description	Page No.
4.19	Effect of Flame Temperature Reduction Method #1 and Limestone on Carbon Monoxide	47
4.20	Effect of Flame Temperature Reduction Method #1 and Limestone on Total Hydrocarbons	48
4.21	Effect of Flame Temperature Reduction Method #1 and Limestone on Peak Flame Temperature	50
4.22	Effect of Flame Temperature Reduction Method #2 and Limestone on Sulfur Dioxide Reduction	52
4.23	Effect of Flame Temperature Reduction Method #2 and Limestone on SO_3	53
4.24	Effect of Flame Temperature Reduction Method #2 and Limestone on NOx	55
4.25	Effect of Flame Temperature Reduction Method #2 and Limestone on Carbon Monoxide	55
4.26	Effect of Flame Temperature Method #2 and Limestone on Total Hydrocarbons	58
4.27	Effect of Flame Temperature Reduction Method #2 and Limestone on Peak Flame Temperature	59
4.29	Foster Wheeler Boundary Air System	73
4.30	Comparison of Measured and Calculated Total Combustion Air	75
5.1	Comparison of NOx and CO Emissions During 2 Different Test Series	78
6.1	Schematic Flow Diagram of Test Facility at Aioi	83
6.2	Controlled Flow/Split Flame Low NOx Burner	86
6.3	Low NO_x Burner Effectiveness on Scale Up: San Juan Test Results	89
6.4	Burner Development NOx Comparison	91
7.1	Phase Discrimination Probe	103

LIST OF TABLES

Table No.	Description	Page No.
4.1	SO_2/SO_3 Capture Across Baghouse	63
4.2	Composite Fuel Analysis	66
4.3	Mass Balance for Test 42	69
4.4	Mass Balance for Test 43	70
4.5	Change in Heating Value of Sized Pulverized Coal After Addition of Limestone at a Ca/S Mole Ratio of 2.15	71
4.6	Ash Fusability Temperature	72
5.1	Fuel Comparison: Japanese & U.S. Coals	79
5.2	Comparison of Flame Temperature Reduction Effectiveness in 1980 and 1983 Test Series	81
6.1	System Specifications	84
7.1	Standard methods	94
7.2	Sample Train Description	97
A-1	Fuel Analysis	A-3
A-2	Limestone Analysis	A-5
A-3	Flyash Analysis	A-6
A-4	Fuel Ash Analysis	A-7
A-5	Heating Value of Sieved Pulverized Coal	A-8
A-6	Test Conditions and Results	A-9
B-1	Recommended Coals for LIMB Testing at IHI	B-6
B-2	Fuels Used In Current EPA Combustion Research	B-7
B-3	Recommended Limestones For LIMB Testing at IHI	B-10

LIST OF ABBREVIATIONS AND SYMBOLS

Abbreviations

Ca/S - Calcium to Sulfur Mole Ratio

OFA - Overfire Air

FTRM#1 - Flame Temperature Reduction Method Number 1

FTRM#2 - Flame Temperature Reduction Method Number 2

PFT - Peak Flame Temperature

THC - Total Hydrocarbons

MCR - Maximum Continuous Rating

Symbols

SO_2 - Sulfur Dioxide

NO_x - Total Nitrous Oxides, Sum of $NO + NO_2$ Expressed as NO_2

CO - Carbon Monoxide

SO_3 - Sulfur Trioxide

CONVERSION FACTORS

To convert from	to	Multiply by
Btu	J	1055
°F	°C	5/9 (°F-32)
in.	m	0.025
lb	kg	0.454
$lb/10^6$ Btu	ng/J	433
Btu/lb	kJ/m	2.324
mbar	Pa	100

1.0 INTRODUCTION

This is the final report on the joint Environmental Protection Agency (EPA) — Foster Wheeler Energy Corporation (FWEC) test program to evaluate the "in situ" sulfur dioxide reduction capabilities of copulverizing limestone injecting the resulting mixture through a low NO_x internally staged burner. The test program was performed during the period of April 13th to May 16th, 1983. The burner used for the program is Foster Wheeler's commercial design Controlled Flow/Split Flame Burner (CF/SF). The test program was designed around the concept that, if the limestone is intimately mixed with the coal during the pulverization process, high SO_2 capture levels may be obtainable. When this method of limestone injection is combined with the low flame temperature characteristics of the CF/SF burner and FWEC's proprietary flame temperature reduction methods, the total SO_2 capture may be enhanced. Success of this system may result in SO_2 reductions at a much lower cost than conventional wet removal methods. Although this technique may not be able to replace wet methods of SO_2 reduction it would be appropriate for a retrofit of existing uncontrolled coal-fired boilers firing high sulfur coals.

The tests were run at Ishikawajima Harima Heavy Industries Co., Ltd. (IHI) Aioi Works Complex in Japan where IHI has a large coal combustion test facility. The use of this facility enhanced the program goals as follows:

1. The CF/SF burner had been tested twice previously for NO_x at this location. The results of these previous tests would provide a basis against which to compare the results of this test series.

2. Program costs could be minimized because the burner suited for the test facility already exists at the Aioi test facility.

3. FWEC's proprietary flame temperature reduction methods were previously tested at Aioi and demonstrated the ability to significantly vary temperature with negligible change in NO_x.

The fuel used for the test program is a high sulfur western Pennsylvania bituminous coal from the Middle Kittaning Seam with a sulfur content of about 3.3%. This fuel was chosen because it is typical of the fuels used in older boilers that may be susceptable to acid rain control legislation. The limestone chosen is Vicron from the Lucerne Valley in California. It is a high calcium content limestone and was chosen because it had been used before in other EPA test programs and would allow more relevent comparison of SO_2 capture among EPA test programs.

2.0 CONCLUSIONS

2.1 Gaseous Emission Levels

- SO_2 Emissions

  The addition of limestone to the fuel at a Ca/S mole ratio of 2.15 resulted in an optimum emission reduction of 28%. This is an improvement over the 22-23% found without any changes in operation of the burner-furnace. This optimum was found with a combination of 20% overfire air and with FWs' proprietary flame temperature reduction method #2 (FTRM#2). Another combination of operating variables (5% excess O_2 and FTRM#2) resulted in high SO_2 reduction at the same Ca/S mole ratio but it also increased NO_x emissions such that the total of acid forming emissions of SO_2 and NO_x was higher then the optimum case.

  Increasing the limestone addition rate during normal operating conditions, to a Ca/S mole ratio of 3.26 resulted in 33.4% reduction. This increase in SO_2 reduction is essentially linear up to Ca/S = 3.26. If the optimum SO_2 control method is extrapolated to Ca/S = 3.26 mole ratio the SO_2 reduction would increase to 43%. Although it has generally been found that SO_2 reduction is not linear with Ca/S mole ratio, we found a linear relationship up to a Ca/S mole ratio of 3.26, the maximum value tested.

- NO_x Emissions

  In general the use of limestone addition to the fuel reduced NO_x by 10%. Under normal operating conditions the NO_x emission rate measured for the CF/SF burner was 0.32 lb/10^6Btu. This represents a 60% reduction from the predicted uncontrolled NO_x emission rate of 0.8 lb/10^6Btu using this fuel and a pre-NSPS burner at this test facility. Under the conditions of optimum SO_2 reduction the NO_x decreased to 0.19 lb/10^6Btu, an additional 41% reduction from 0.32 lb/10^6 Btu or a total of a 76% reduction from the uncontrolled level. About 25 to 30% of this additional NO_x reduction can be attributed to overfire air (OFA), 10% can be attributed to the use of limestone addition to the fuel and 1% is attributed to the use of FWs' proprietary flame temperature control #2.

- CO Emissions

  In general the use of limestone addition at a Ca/S of 2.15 reduced CO concentrations at the economizer outlet to below 35 ppm corrected to 0% excess O_2, with one exception. Under normal operating conditions the CO averaged 39 ppm. Under the optimum SO_2 reduction test conditions the CO concentration dropped to 24 ppm, a 38% reduction. Half of this reduction can be attributed to limestone addition, the remainder can be attributed to flame temperature reduction method #2 (FTRM #2).

- SO_3 Emissions

  In general the use of limestone addition to the fuel at a Ca/S = 2.15 always reduced SO_3 concentrations to below 20 ppm corrected to 0% excess O_2 regardless of the initial concentration. Under normal operating conditions SO_3 concentrations averaged 28 ppm. Under conditions of optimum SO_2 reduction the SO_3 concentrations were reduced to 8 ppm, a 71% reduction. About equal percentages of this reduction can be attributed to OFA and limestone addition.

- Total Hydrocarbons (THC)

  Limestone addition in many cases decreased the THC emissions but there were many exceptions. The only operating variable that had a consistent effect on THC was FTRM #1 and it increased THC. Neither excess oxygen nor overfire air had a consistent effect on THC. Under normal operating conditions the THC concentrations averaged 3 ppm corrected to 0% excess O_2. Under conditions of optimal SO_2 reduction the THC was reduced to 1.7 ppm, a 43% reduction. The reduction is attributed to a synergistic effect of the combination of OFA, FTRM #2 and limestone addition since none of these consistently reduced THC.

2.2 SO_2 Capture in the Baghouse

No SO_2 or SO_3 reduction was measured across the baghouse. SO_3 reduction was measured across the airheater. SO_3 concentrations dropped from an average 8 ppm to about 0.3 ppm when limestone was being added; SO_3 was reduced from 18.3 ppm to 0.6 ppm when limestone was not being added and further reduced to 0.4 ppm across the baghouse. The air heater is a tubular design with exit temperature of about 500^oF (270^oC). Consequently, there should be no SO_3 condensation prior to the baghouse. At these tempertures the SO_3 level should remain constant unless absorption is occurring on some surface.

All test results shown are corrected to 0% excess oxygen, the actual measured results are shown in Appendix A.

2.3 Effect on Equipment

- Furnace

  No detrimental side effects were noted. The addition of limestone to the fuel did not increase the slagging potential of the coal. The coal was considered to be of medium to high slagging potential. During normal combustion, both with and without limestone, slagging was not evident, but when overfire air was used slagging was evident, both with and without limestone. This was fully expected based on an analysis of the ash constituents and oxidizing/reducing fusion temperatures.

- Baghouse

  The baghouse operated normally during the test program. No increase in pressure drop was seen. The daily startup - shutdown cycle did not precipitate any bag blinding.

- Burner

  No detrimental side effects were noticed on the burner, flame or combustion in general.

- Phase Discrimination Probe

  During the first two days of testing with limestone the probe plugged. Consequently, the internal clearances were increased and the probe did not plug for the remainder of the test series.

2.4 Application to full Scale

Although it was shown that the SO_2 reduction could be improved through the use of operating changes and flame termperature reduction methods the absolute SO_2 reduction achievable was well below the target of 50% reduction at a Ca/S mole ratio of 2.5. Based on the low SO_2 removal rates a full scale application of copulverization of coal and limestone is not recommended with this burner.

3.0 BACKGROUND

The concept of in situ sulfur capture, within a coal-fired steam generator, has been investigated since the 1960's. However, most of this work failed due to a number of reasons:

(a) The sorbent was dead burned due to the high flame temperatures encountered in the older steam generators evaluated.

(b) Most of the units tested were burning high sulfur bituminous coal. The slagging properties of this fuel are such that, as the calcium content increases, ash fusion temperature will decrease. Thus, adding limestone to boilers which have high furnace zone liberation rates, and firing high sulfur bituminous coal, resulted in unacceptable slagging.

(c) Almost all of the older units tested used higher turbulent pre-NSPS (New Source Performance Standards) coal burners. These promote rapid mixing between the fuel and air streams thereby producing high flame temperatures along with short residence times in the flame.

There was, however, one test which yielded moderate success. This was performed on an 85 MW arch-fired boiler in the Wisconsin Electric Power Company's (WEPCo) system. At calcium to sulfur mole ratio (Ca/S) = 1.3 sulfur capture was approximately 45%, when limestone was pulverized simultaneously with the coal. Apparently no attempt was made to optimize this effect since the investigators were evaluating a flue gas scrubber. The successful test at WEPCo was likely due to the nature of the arch-fired system's flame pattern and temperatures. The boiler, shown in Figure 3.1, injects the coal and primary air downwards, with the remainder of the combustion air being injected horizontally from the front wall. This results in a flame which is inherently staged. Also, this unit has a lower furnace zone liberation rate than the wall-fired units tested with limestone injection. The combination of the staged flame and cooler furnace produced a lower flame temperature and longer residence time which seems to enhance the effectiveness of pre-mixing limestone with coal. The effectiveness of the cooler furnace and the staged combustion system is

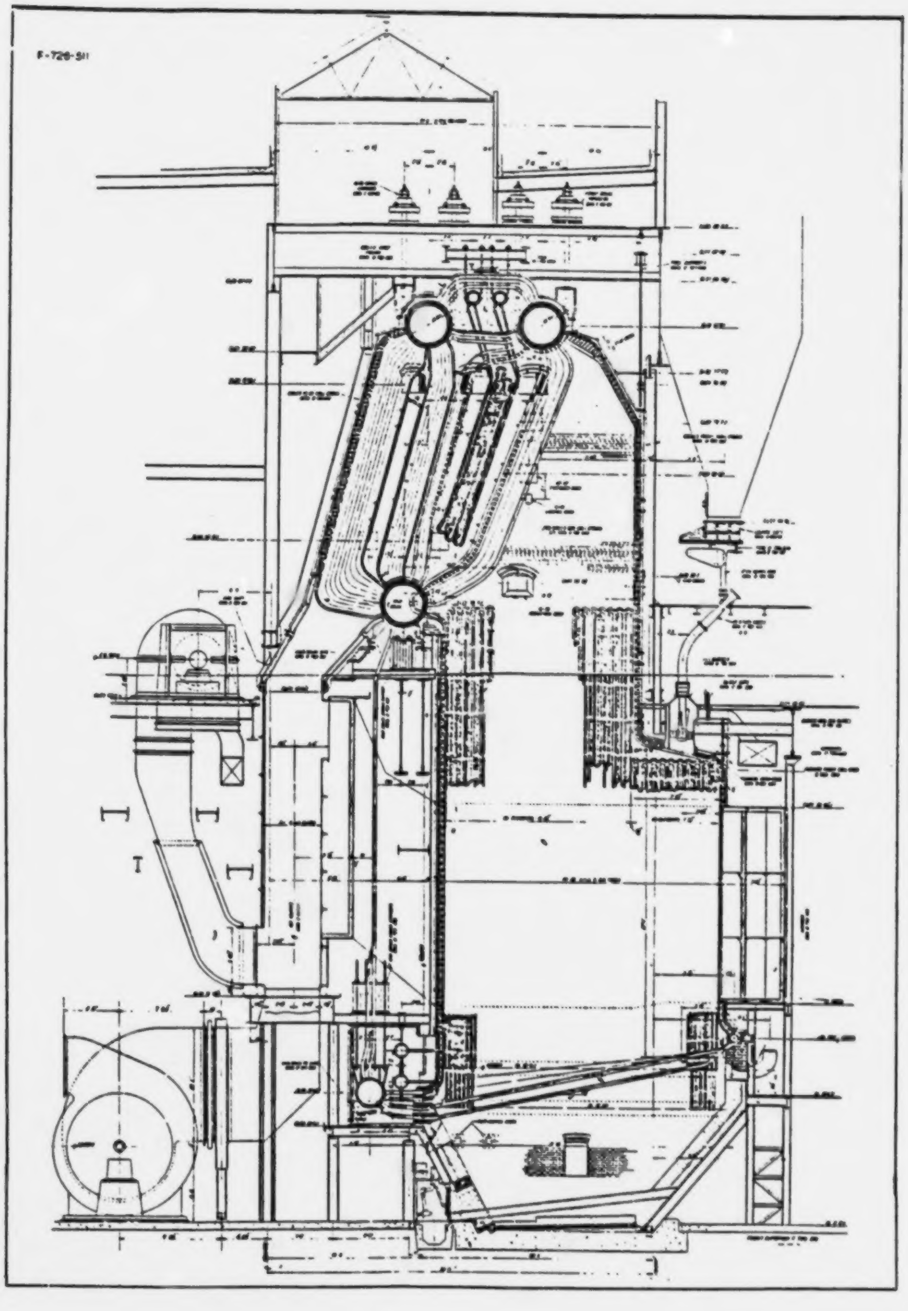

FIGURE 3.1: ARCH-FIRED BOILER

shown by the relatively low NO_x levels emitted from this unit: 300 ppm as compared to values typically two to three times as great from wall-fired units of similar vintage.

Prior to commencement of this program promising results were obtained by EPA's contractor, Energy and Environmental Research Corporation (EERC), on a 10 million Btu/hr test facility. An experimental version of the Distributed Mixing Burner (DMB), shown in Figure 3.2, was evaluated with both a low sulfur Utah coal and a high sulfur Kentucky coal. The results, as presented at the third meeting of the DMB Technology Transfer Panel in September 1979, are summarized as follows:

			% Reductions	
COAL:	Ca/S	1.0	2.0	3.0
Utah		53	73	88
Kentucky		50	-	-

These data were taken by simultaneously pulverizing coal and limestone and then combusting the mixture in a staged flame. The flame stoichiometry being about 70%.

More recently, EERC's tests, on various facilities, have yielded much lower capture ratios. In general, the capture seen by pre-mixing coal and limestone have been about one-half that of injection external to the burner, through tertiary air ports.

FWEC, through its involvement with EERC on EPA contract 68-02-3127, has been actively involved in converting the DMB concept into a viable field operating system on a 20 MW utility steam generator. The DMB, which has demonstrated NO_x levels below 200 ppm on a prototype burner in the 3127 program, operates by reducing burner throat stoichiometry to approximately 70% and injecting the remainder of the combustion air through tertiary air ports surrounding the burner. There is, therefore, a relatively long residence time at reducing conditions. This results in lower flame temperatures while permitting the nitrogenous species to leave the coal under conditions more favorable to the formation of N_2 than NO. These conditions also appeared to favor the formation of $CaSO_4$ when limestone is injected into the flame by premixing with coal.

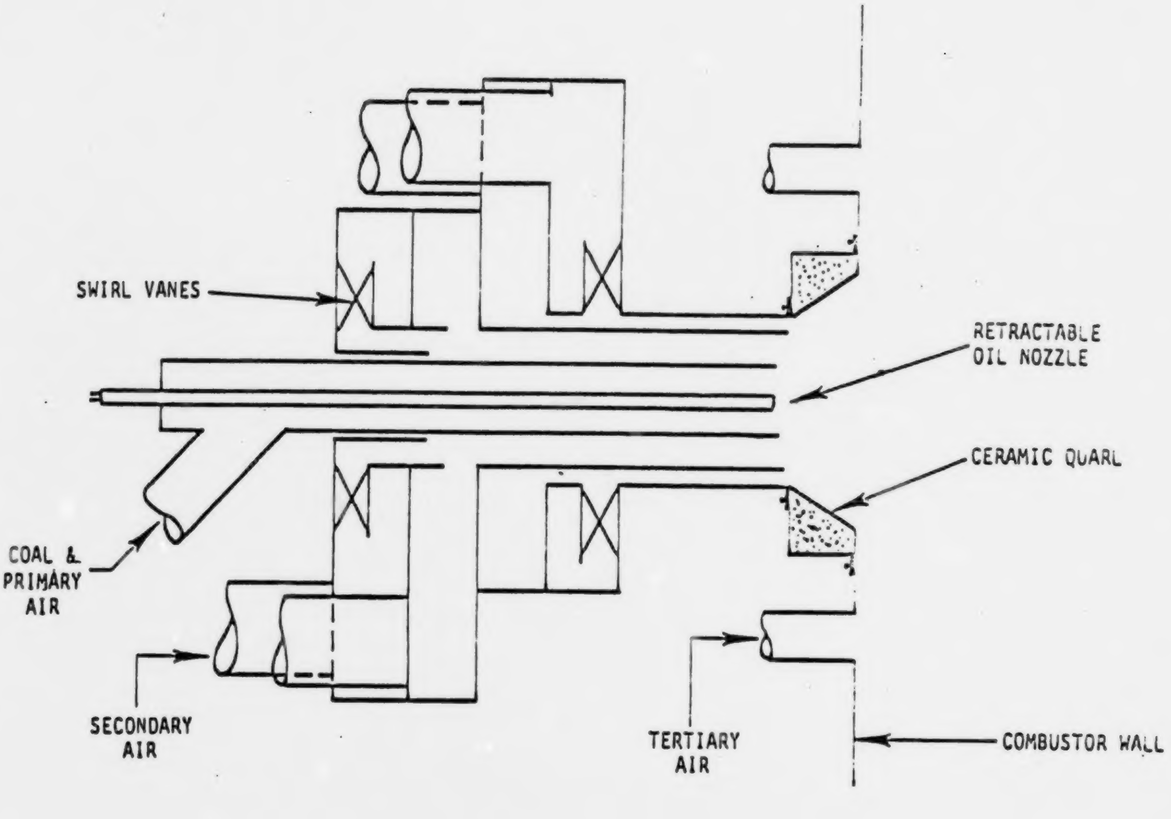
SWIRL VANES
RETRACTABLE
OIL NOZZLE
CERAMIC QUARL
COAL &
PRIMARY
AIR
SECONDARY
AIR
TERTIARY
AIR
COMBUSTOR WALL

FIGURE 3.2: EXPERIMENTAL DISTRIBUTED MIXING BURNER

The Foster Wheeler Controlled Flow/Split-Flame (CF/SF) low NO_x burner, schematically shown in Figure 3.3, is an internally staged burner. NO_x is controlled by staging the near throat portion of the flame to approximately 70% stoichiometry while the throat operates at normal excess air. Functionally, the burner is triple-staged, without resorting to external staging ports, in the following manner.

- A two-stage effect is imparted to the secondary air by the dual registers. The secondary air flows axially into the furnace with almost no component directed radially inward toward the burner centerline; further into the furnace the outer register destroys this non radial flow with high turbulence completing the burnout. Two registers permit the mixing rate between the primary and secondary air streams and the rate of entrainment of furnace gases to be controlled.

- The split-flame coal nozzle injects the coal into the furnace as four concentrated streams. A portion of the primary air is removed from the coal streams thereby increasing the concentration of coal in the near throat region of the flame. This provides further staging to the flame.

The combination of the concentrated coal streams produced by the split-flame nozzle and the staged secondary air yields the triple staging effect. Near-throat flame stoichiometries of approximately 70% are attained with the overall throat operating at normal excess air (typically 20% or 120% stoichiometry). In addition, the coal nozzle also contains an axially movable inner tip to allow control of primary air/coal velocity without changing flow rates.

The low flame temperature and low stoichiometry developed by the Foster Wheeler burner are similar to that developed by the DMB. Consequently the sulfur capture ratios were expected to be similar.

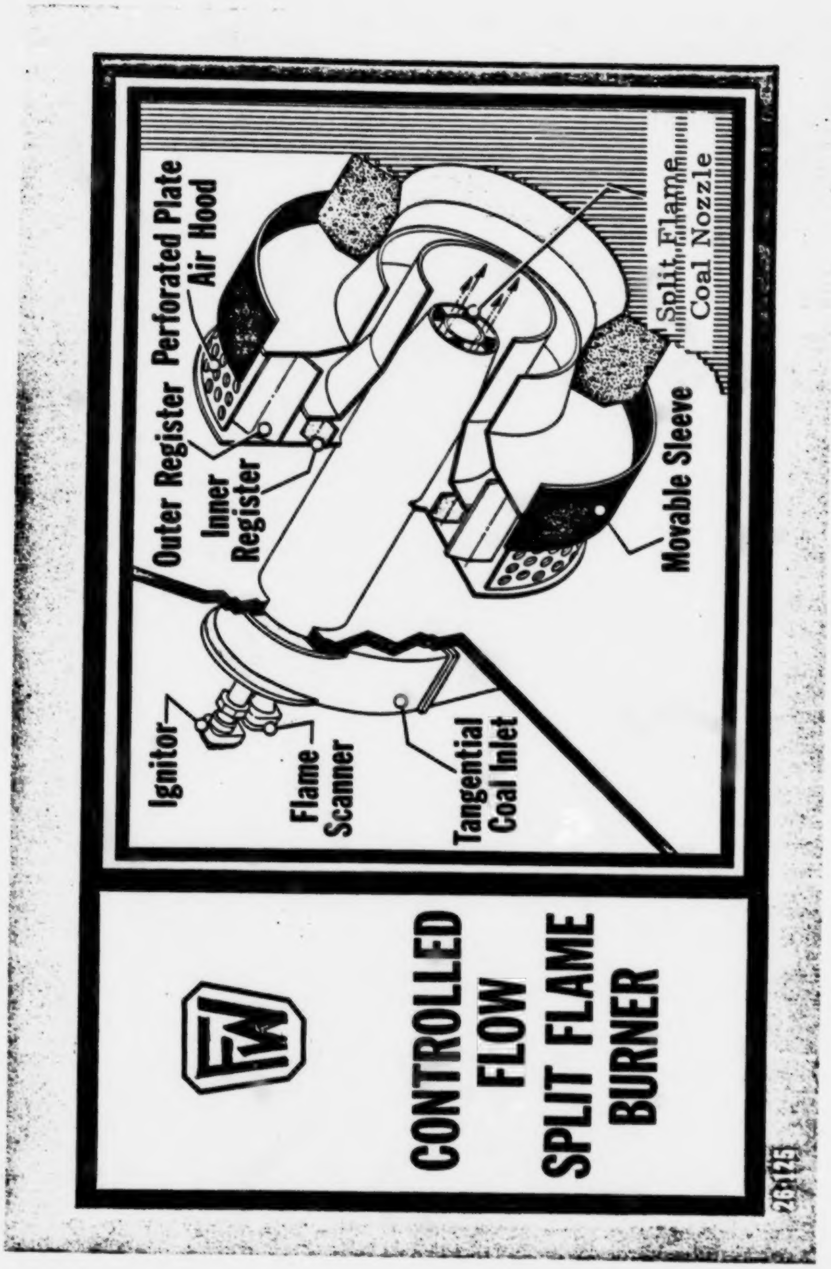
CONTROLLED FLOW SPLIT FLAME BURNER
Ignitor
Flame Scanner
Tangential Coal Inlet
Outer Register
Inner Register
Perforated Plate Air Hood
Split Flame Coal Nozzle
Movable Sleeve
26-1725

FIGURE 3.3: CONTROLLED FLOW SPLIT FLAME BURNER

The following tabulation compares the DMB with the CF/SF concept:

	DMB	CF/SF
Throat Stoichiometry @ 20% excess air	70%	120%
Near-Throat Flame Stoichiometry	70%	70%
Residence time at 70% Stoichiometry	Medium	Short
Flame Temperature Control	No	Yes
Method of Staging	External to Throat	Internal to Throat

With the DMB or the CF/SF burner, limestone can be premixed with the coal and pulverized with it. Although the residence times and mixing rates are different, the flame temperature control method utilized with the CF/SF burner should enable optimum conditions for maximum sulfur capture to be determined.

FWEC has developed two proprietary flame temperature control methods for the purpose of improving SO_2 capture. This has the potential for improving SO_2 capture by minimizing the dead burning of the limestone as it passes through the flame which reduces the limestone's activity. Minimization of dead burning allows the limestone and coal to be intimately mixed maximizing the residence time of the limestone in the zone of highest SO_2 concentration.

A primary purpose of this test program is to determine if these potential advantages do in fact enhance the sulfur capture effect when limestone is premixed with coal.

4.0 TEST RESULTS

The test program was set up to evaluate those operating variables that would have the greatest impact on SO_2 reduction and, simultaneously to evaluate how other emission species and boiler operation would be affected. The test program was broken down into four (4) phases to achieve these goals.

1. Baseline verification
2. Burner optimization
3. SO_2 reduction optimization
4. Long term effects

Baseline verification was designed to show that the burner was working effectively and consistant with previous test programs and to optimize register settings for NO_x emissions, CO concentrations, excess air and carbon burnout. Incorporated in phase I was an equipment shakedown period to insure all equipment was working properly. The results of these tests are shown in Section 5.

Burner optimization was designed to see how the addition of limestone affected burner operation and to see if burner adjustments could be used to increase SO_2 capture without affecting NO_x, CO, excess O_2 or carbon burnout.

SO_2 reduction optimization consisted of a set of experiments designed to evaluate operating variables ie. excess oxygen, overfire air (OFA), flame temperature reduction methods one and two (FTRM#1&2), calcium to sulfur (Ca/S) mole ratio and load. The experiments were designed to allow analysis of variance to be used to evaluate the test results, but unfortunately problems during testing did not allow sufficient tests to be taken to completely fill the matrix. Consequently the tests were evaluated in small groups.

Long term effects tests were designed to evaluate at the optimum SO_2 reduction conditions, parameter variation with time. Additional measurements were taken during the long term tests to to measure SO_2 capture on the sorbant cake in the baghouse.

The variation in the fuel sulfur content is shown in Figure 4.1. The figure shows the fuel SO_2 content as measured by two different methods, by fuel analysis and by flue gas analysis. Except for three obvious outliers measured by fuel analysis the two methods show excellent agreement. Of the 30 valid data points the mean is 4.98 lb/10^6Btu and the standard deviation is 0.1945; the coefficient of variation is 3.83% (ie. 68.27% of the data are within 3.83% of the mean). The average of the 7 measurements by fuel analysis is 4.91 lb/10^6Btu (outliers excluded), standard deviation is 0.2238; the average of the 23 flue gas measurements is 5.0048 lb/10^6Btu, standard deviation is 0.1844. If we were to assume that 97.5% of the SO_2 is emitted by the boiler (based on AP-42)[1] then the SO_2 measured in the flue gas should be 0.975 of the SO_2 in the fuel (the ash analysis corroborates this effect of about 2.5% capture of SO_2 in the ash, 2.0% was measured). The bias in measuring can thus be estimated as follows:

$$0.975 \times 4.91 - 5.005 = -0.218 \text{ lb}/10^6 \text{ Btu}$$

or $$(0.218/4.91) \times 100\% = 4.43\%$$

Thus the total bias is 4.43% but the average bias of each measurement method is 2.2% since the bias must be shared between the two measurement methods.

Since the SO_2 variability is quite low, and there is no trend in the measured SO_2, the average SO_2 content of 4.98 lb/10^6 Btu will be used for all estimates of SO_2 reduction over the test series. Note the measurements shown on the last 3 test days were taken as part of a separate test program by FW and are not part of the EPA-sponsored testing. The same fuel was used for these three test days. The data indicate that fuel sulfur did not change during this time period.

The following subsections contain evaluations of all data variables. Results are presented graphically in parametric map form.

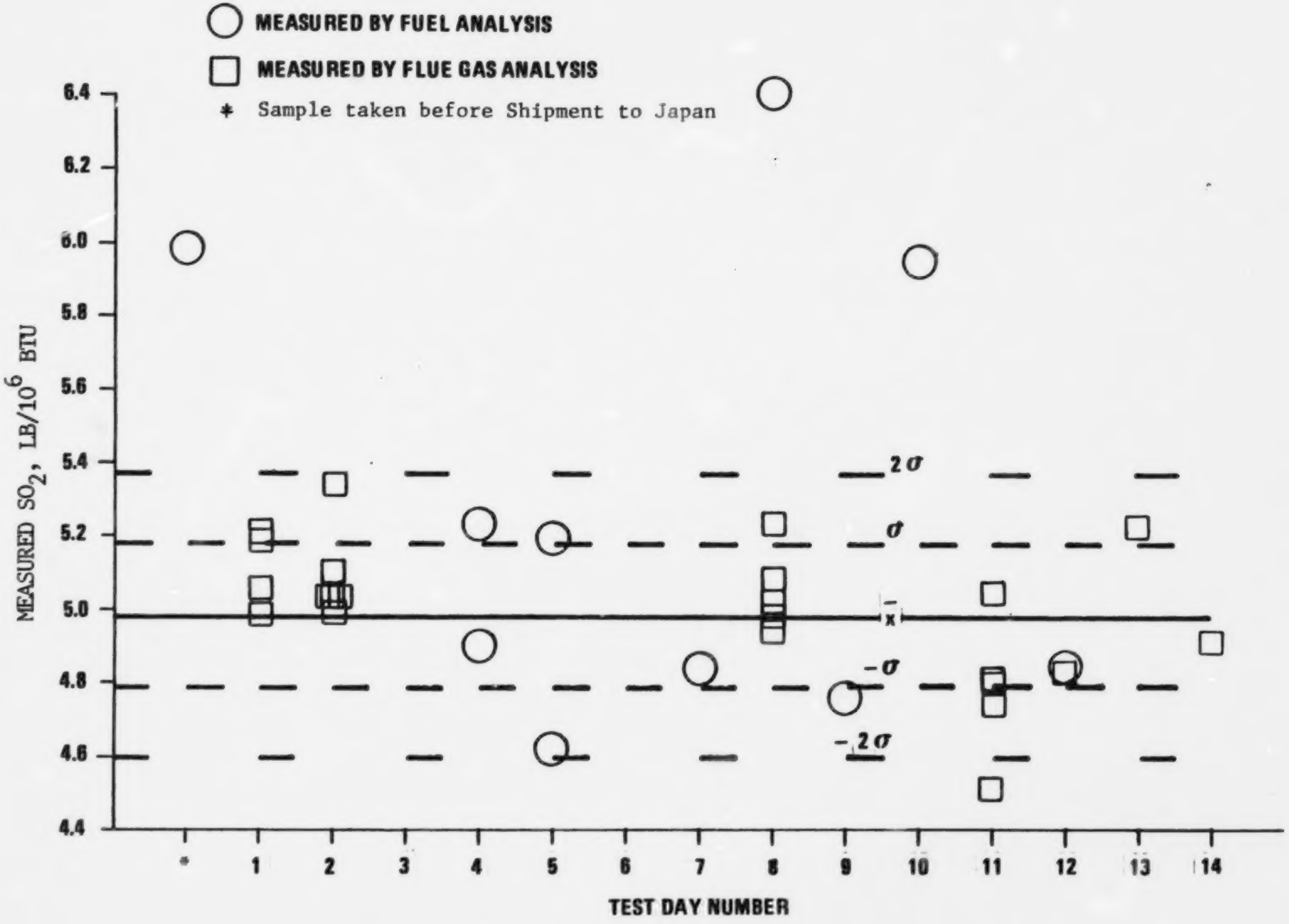

FIGURE 4.1: VARIATION IN THE FUEL USED AT AIOI

The graph symbols are arranged so that the square symbol always represents the main effect of the variable compared to the normal operating conditions. Normal operating conditions are:

Burner set at optimum NO_x levels
Excess $O_2 = 3.0\%$
No limestone added
No overfire air
No flame temperature reduction method used
Full Load

All the other symbols used show the effect of some other variable for all tests using that symbol. The difference between the two results represents the effect of the added variable only.

The equations at the top of each graph represent a best fit multilinear regression of the data. SEE is the standard error of the estimate. SEE is an unbiased estimate of the standard deviation of the regression line; it is a measure that shows the degree of dispersion of the data around the regression line,[2] it is analogous to the standard deviation. The next set of numbers in the same line are (xleft, xright) used to generate the representative lines drawn on the graphs. For example on Figure 4.2 xleft = 2.15 this value is held constant while the regression curve on the right side is plotted, similarly xright is held constant at 1500 kg/hr while the plot on the left is generated. The plot is represented by the small symbols connected by the regression line; the large symbols are actual data points. Curves labeled as normal operating conditions pass through data points of normal operating conditions but they also show how a change of a single variable (in Figure 4.2 it would be coal rate or Ca/S mole ratio) affects the dependent variable. Other data symbols represent the differential effect of an added variable; for these plots the effect of the dependent variable is still shown in relation to the independent value but with the constant operation of a third variable. The equations can generate a family of curves and actually represent the projection of a surface on two orthogonal planes each plane represented by an independent variable.

4.1 Effect of Load and Upper Overfire Airports

4.1.1 Effect of Load (Figure 4.2)

Test 29 evaluated the effect of lower load. Reducing the load to 75% of normal load decreased the SO_2 reduction by 1%. The NO_x emission rate did drop to 0.25 lb/10^6Btu from the average of 0.32 at normal operating conditions.

4.1.2 Effect of Lower Overfire Airports Vs Upper Overfire Airports (Figure 4.3)

The unit at AIOI has two sets of overfire air ports (OFA). One set is located about one burner level above the burner the second is located about two burner levels above the burner. The lower ports are in the conventional port location. Some tests were run to see if the upper ports would have any effect on the SO_2 reduction during limestone in addition. Since no significant improvement was achieved, and in general these upper ports would be harder to retrofit, no further testing was done with them.

4.2 Higher Excess Oxygen and Limestone

4.2.1 Effect On SO_2 Reduction (Figure 4.4)

Under normal operating conditions excess O_2 had no effect on the sulfur dioxide reduction. An average of about 22% reduction was achieved regardless of the excess O_2 measured at the economizer outlet. When the Ca/S mole ratio was increased to 3.26 the SO_2 reduction increased to 34%. When high excess O_2 is combined with FTRM #2 the SO_2 reduction becomes sensitive to excess O_2; at 5.0% excess O_2 the reduction increased to 31% almost as high a reduction was achieved at a nominal Ca/S of 3.26. Unfortunately, this same mode of operation resulted in the highest NO_x levels seen during the test program 0.62 lb/10^6 btu (figure 4.6); the increase in NO_x more than counterbalanced the SO_2 reduction.

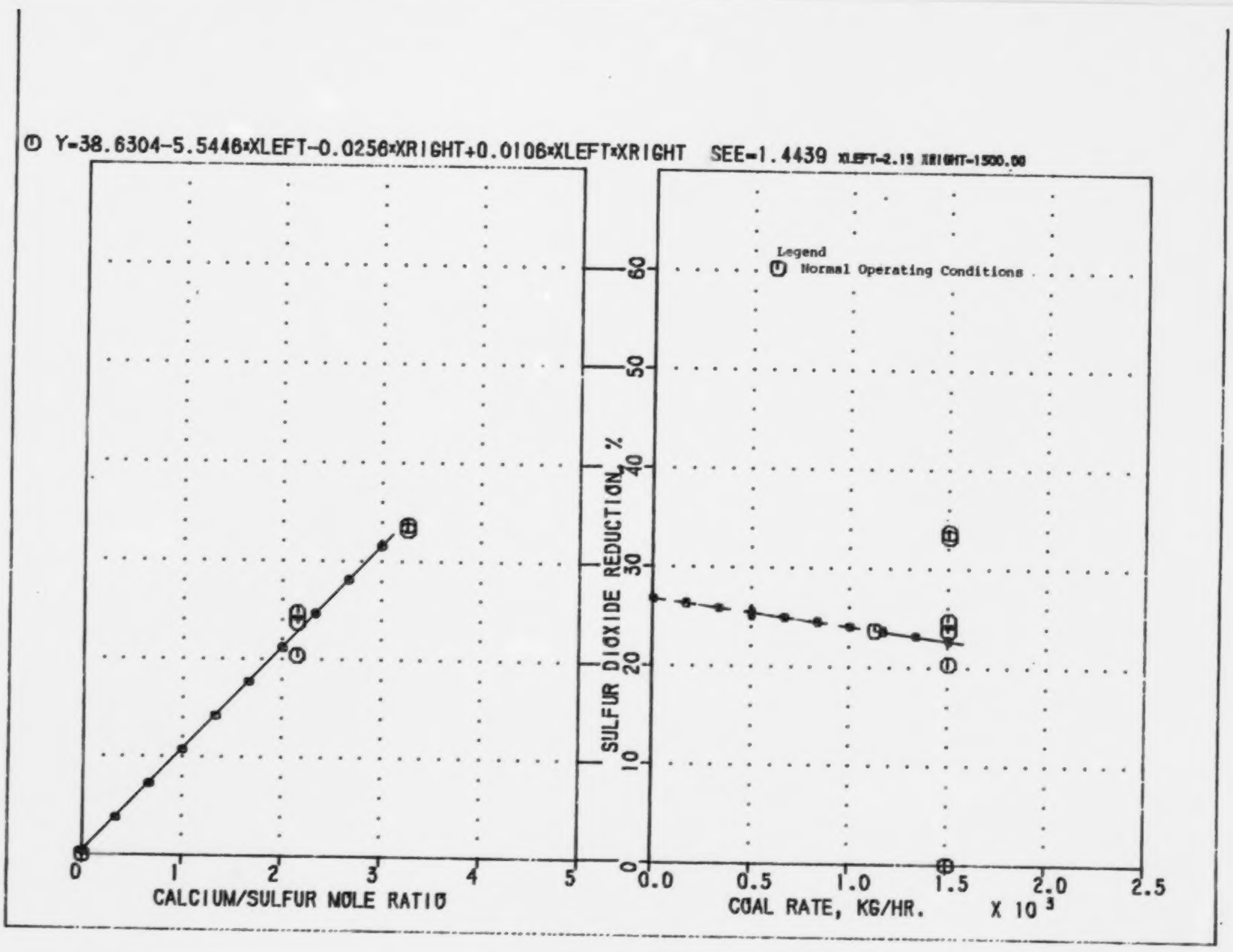

FIGURE 4.2: EFFECT OF LOAD AND LIMESTONE ON SO_2 REDUCTION

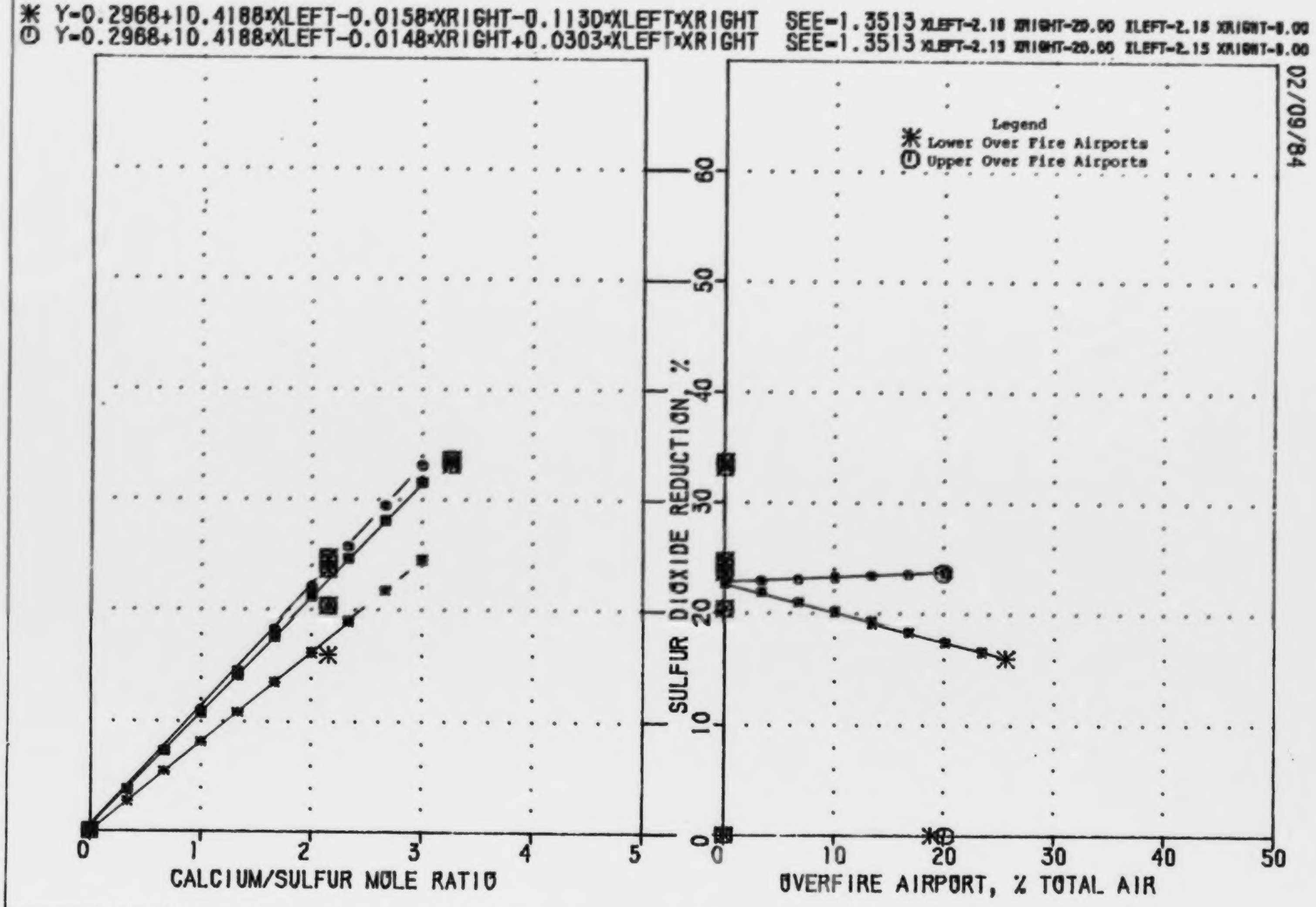

FIGURE 4.3: COMPARISON OF THE EFFECT OF LOWER AND UPPER OVERFIRE AIRPORTS

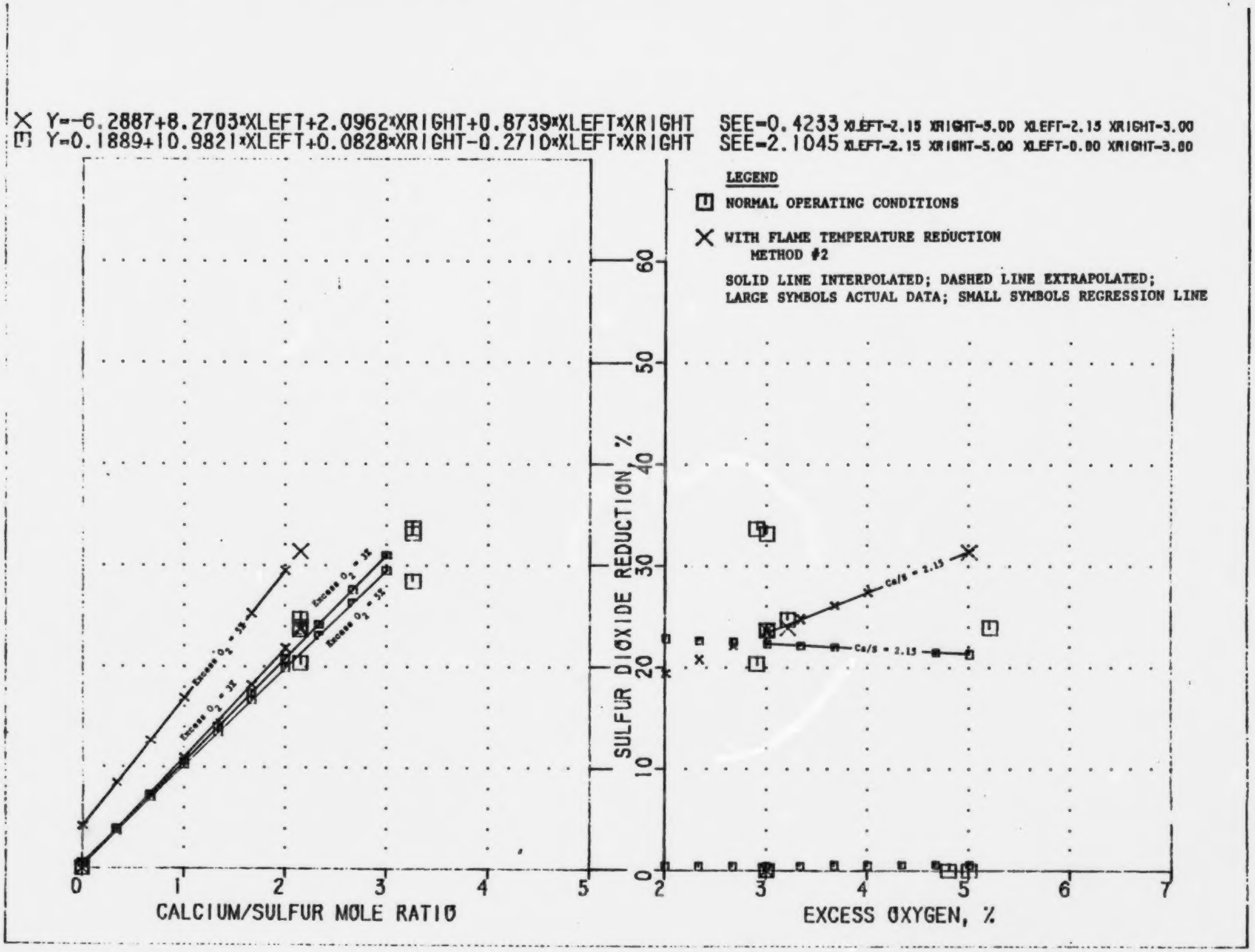

FIGURE 4.4: EFFECT OF EXCESS OXYGEN AND LIMESTONE ON SO_2 REDUCTION

4.2.2 Effect On SO_3 Concentration (Figure 4.5)

The effect of limestone on the sulfur trioxide concentrations is quite dramatic. Under normal operating conditions the SO_3 was reduced from 28 ppm to about 12 ppm corrected to 0% excess O_2 when the limestone was added at a Ca/S of 2.15, a 57% reduction. Increasing the limestone addition rate to a Ca/S mole ratio 3.26 reduced the SO_3 to 8 ppm a 71% reduction. When the excess O_2 is increased to 5.0% the SO_3 increased to 69 ppm (a 146% increase) without limestone; when the limestone was added at a Ca/S of 2.15 the SO_3 decreased to about 17 ppm, a 75% reduction.

When FTRM #2 was used at 3% excess O_2 the SO_3 concentration dropped from 38 ppm to about 11 ppm at a Ca/S mole ratio of 2.15. Increasing the excess O_2 to 5.0% had almost no effect on the SO_3 concentration at a constant Ca/S mole ratio.

4.2.3 Effect on NO_x (Figure 4.6)

The addition of limestone had a slight effect on NO_x. Under normal operating conditions about a 10% reduction in NO_x was recorded when the limestone was added at a Ca/S mole ratio of 2.15. Increasing the excess O_2 from 3 to 5% increased the NO_x from 0.31 lb/10^6Btu to .44 lb/10^6Btu, a 38% increase. This is a typical increase in NO_x with excess O_2.

When the FTRM #2 was used in combination with 5% excess O_2 the NO_x increased from 0.3 lb/10^6Btu to 0.62 lb/10^6Btu. However, at 3% O_2, FTRM#2 had essentially no effect on NO_x. This large increase in NO_x from using FTRM #2 and high excess O_2 would offset the improved reduction in SO_2 using this same combination (shown in Figure 4.4), hence this is not an optimum operating combination.

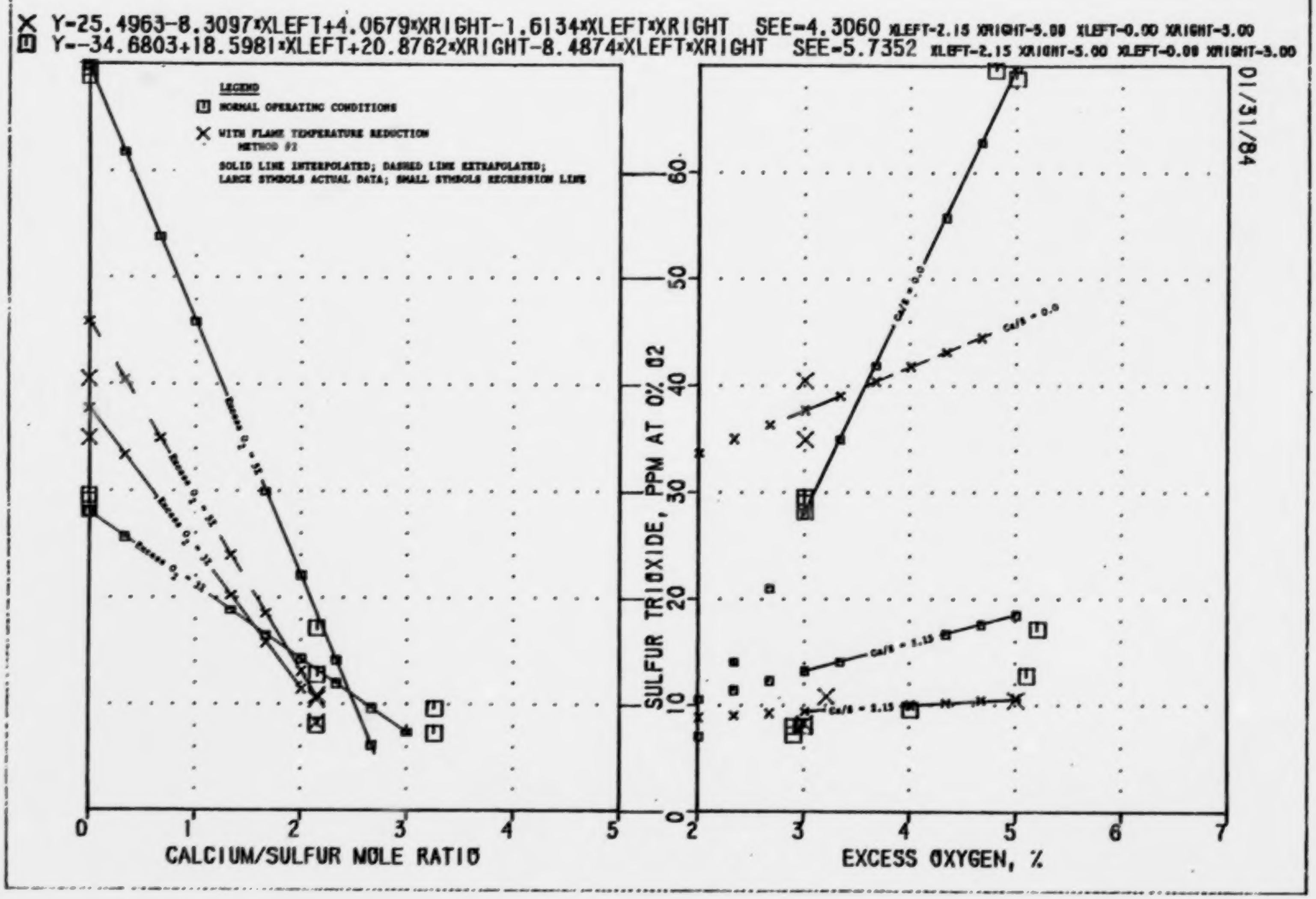

FIGURE 4.5: EFFECT OF EXCESS OXYGEN AND LIMESTONE ON SULFUR TRIOXIDE

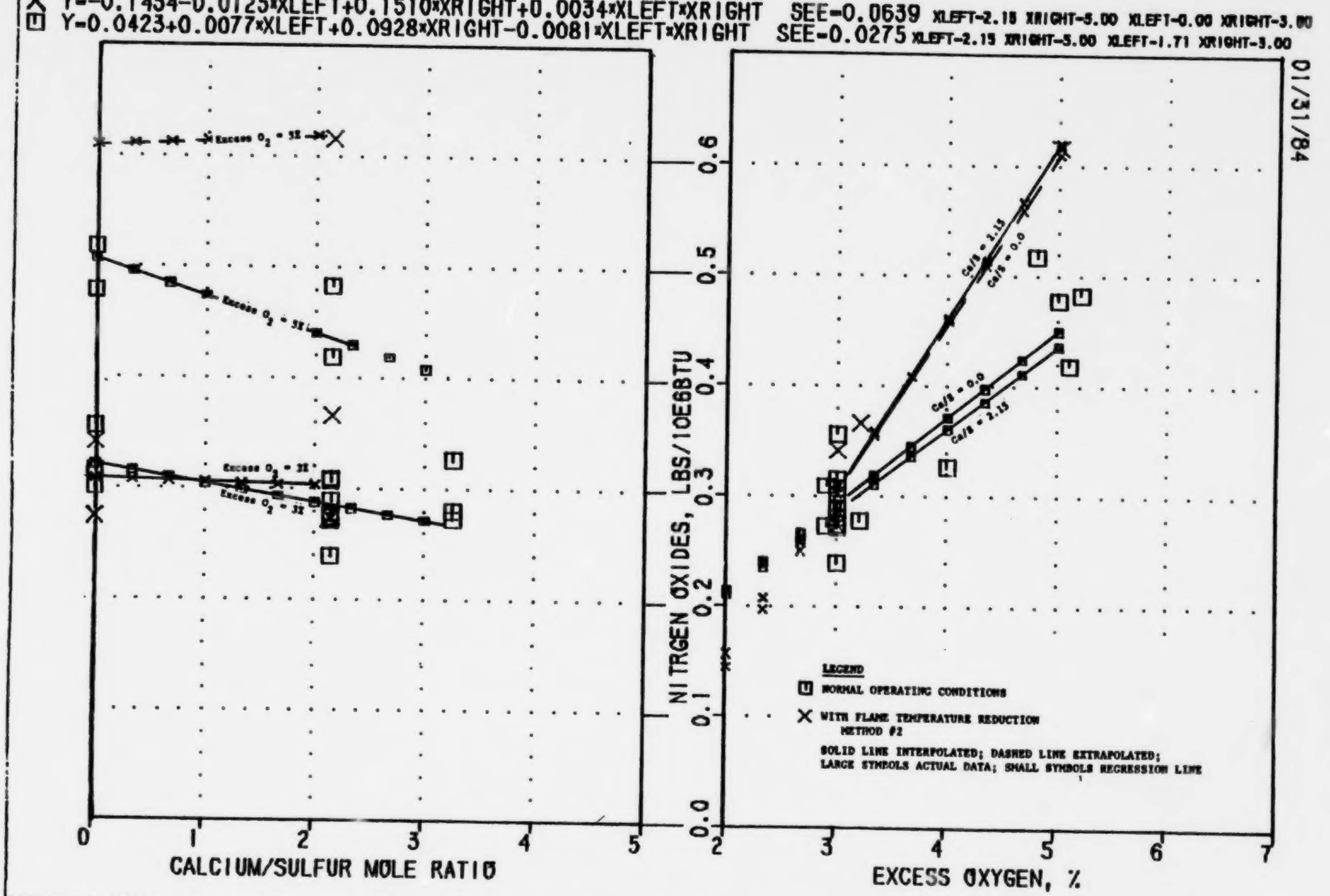

FIGURE 4.6: EFFECT OF EXCESS OXYGEN AND LIMESTONE ON NOx

4.2.4 Effect on Carbon Monoxide (Figure 4.7)

In general an increase in the excess O_2 decreased the CO. Under normal operating conditions the addition of limestone to the fuel at a Ca/S mole ratio of 2.15 resulted in a reduction of CO from an average of 29 ppm to 13 ppm, a 55% reduction. At 5% excess O_2 the addition of limestone at a Ca/S of 2.15 caused the CO to drop from an average of 19 ppm to 5 ppm, a 74% reduction. At a Ca/s mole ratio of 3.26 the CO decreased to zero at both 3 and 4% excess O_2.

The addition of FTRM #2 did not change the general effect that limestone or excess O_2 had on the CO concentration, although at 5% O_2 and a Ca/S mole ratio of 2.15 the CO decreased to zero.

4.2.5 Effect on Total Hydrocarbons (Figure 4.8)

The addition of limestone to the fuel under normal operating conditions at a Ca/S mole ratio of 2.15 reduced the THC from 3 ppm to 2 ppm; slight additional reductions at a Ca/S mole ratio of 3.26 were seen. Under normal operating conditions increasing the excess O_2 increased the THC. This increase was unexpected; the increase was especially strong without limestone addition. At 5% excess O_2 the THC without limestone increased to 13 ppm. Normally THC would be expected to decrease with increasing excess O_2 because of the improved burnout.

When FTRM #2 is added the THC decreased when the Ca/S mole ratio is increased or when the excess O_2 is increased.

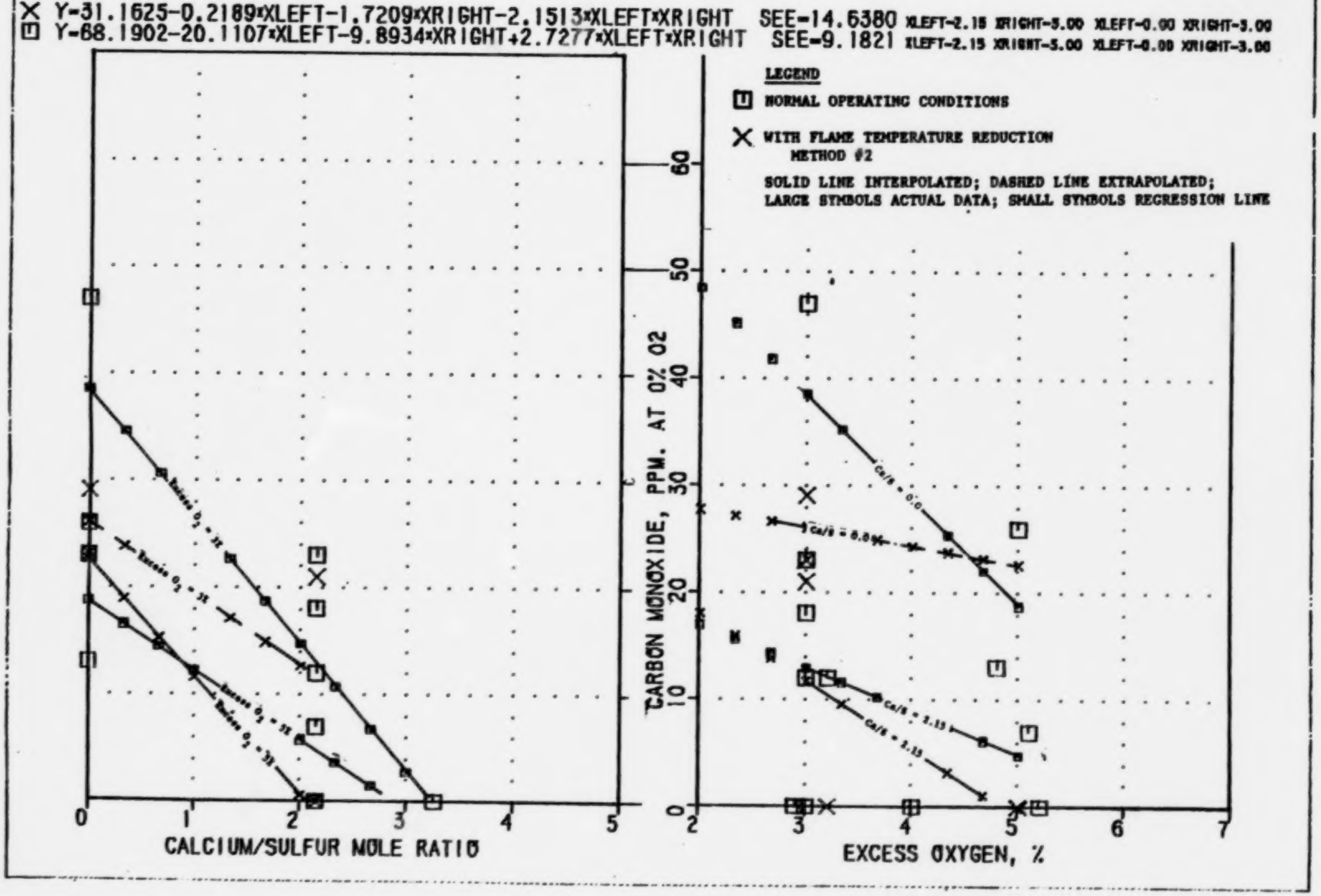

FIGURE 4.7: EFFECT OF EXCESS OXYGEN AND LIMESTONE ON CARBON MONOXIDE

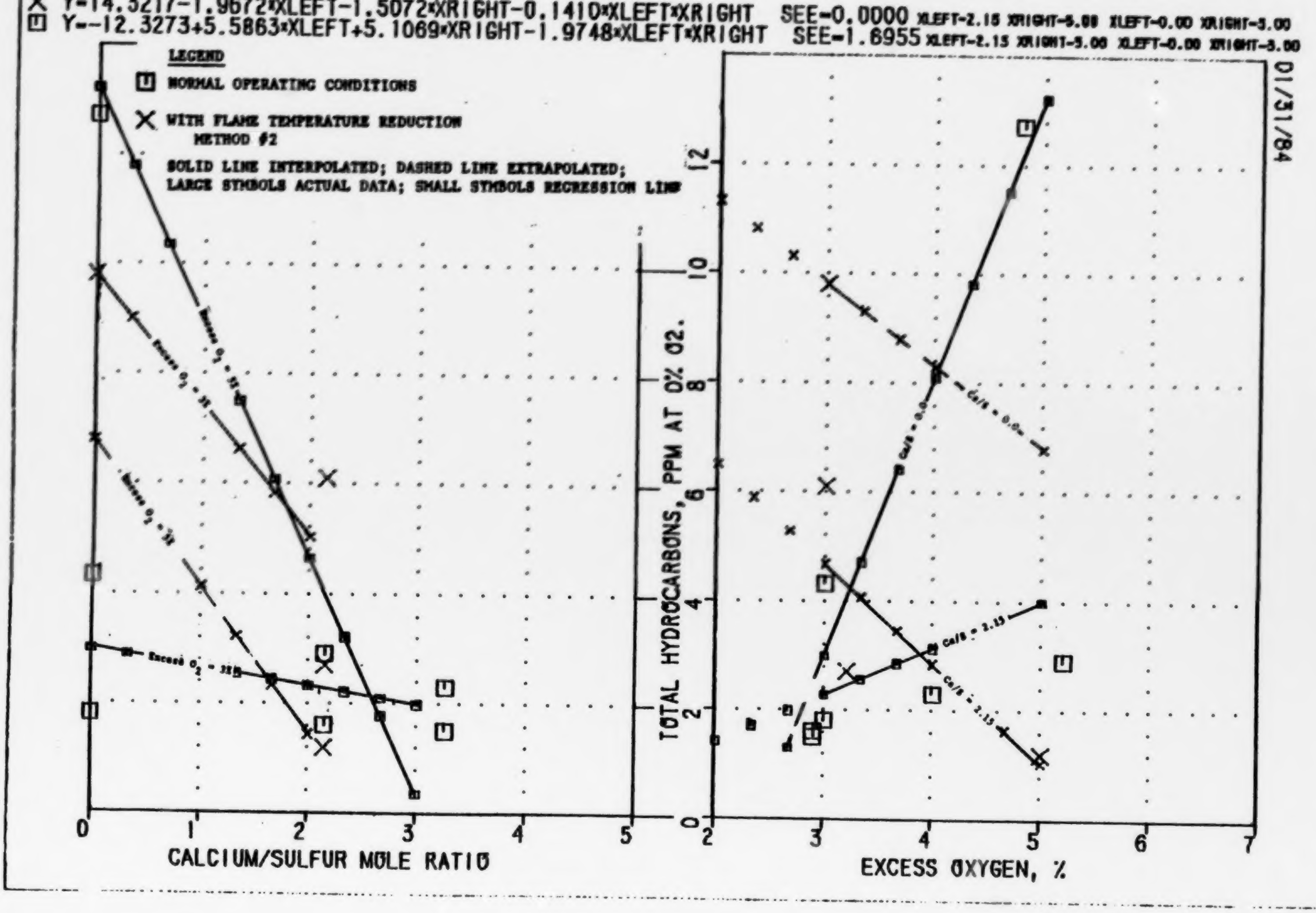

FIGURE 4.8: EFFECT OF EXCESS OXYGEN AND LIMESTONE ON TOTAL HYDROCARBONS

4.2.6 Effects on Peak Flame Temperature (Figure 4.9)

Under normal operating conditions addition of limestone to the fuel at a Ca/S mole ratio of 2.15 reduced the peak flame temperature by about 25°C (45°F). Increasing the excess O_2 to 5% without limestone addition increased the peak flame temperature an average of 25°C (45°F). The combination of 5% excess O_2 and a Ca/S mole ratio of 2.15 tended to cancel each other out with a net average peak flame temperature reduction about 2°C (4°F).

When FTRM #2 was added at 3% excess O_2 without limestone addition an average peak flame temperature reduction of 42°C (76°F) was seen; these same results were achieved when limestone was added at a Ca/S of 2.15. The combination of 5% excess O_2, a Ca/S mole ratio of 2.15 and FTRM #2 increased the flame temperature 7°C (13°F) above normal operating conditions. This small and probably insignificant increase in flame temperature accompanied the best SO_2 reduction of 31% at a Ca/S mole ratio of 2.15. The flame temperature decrease obtainable with this fuel is not sufficient to improve SO_2 reduction.

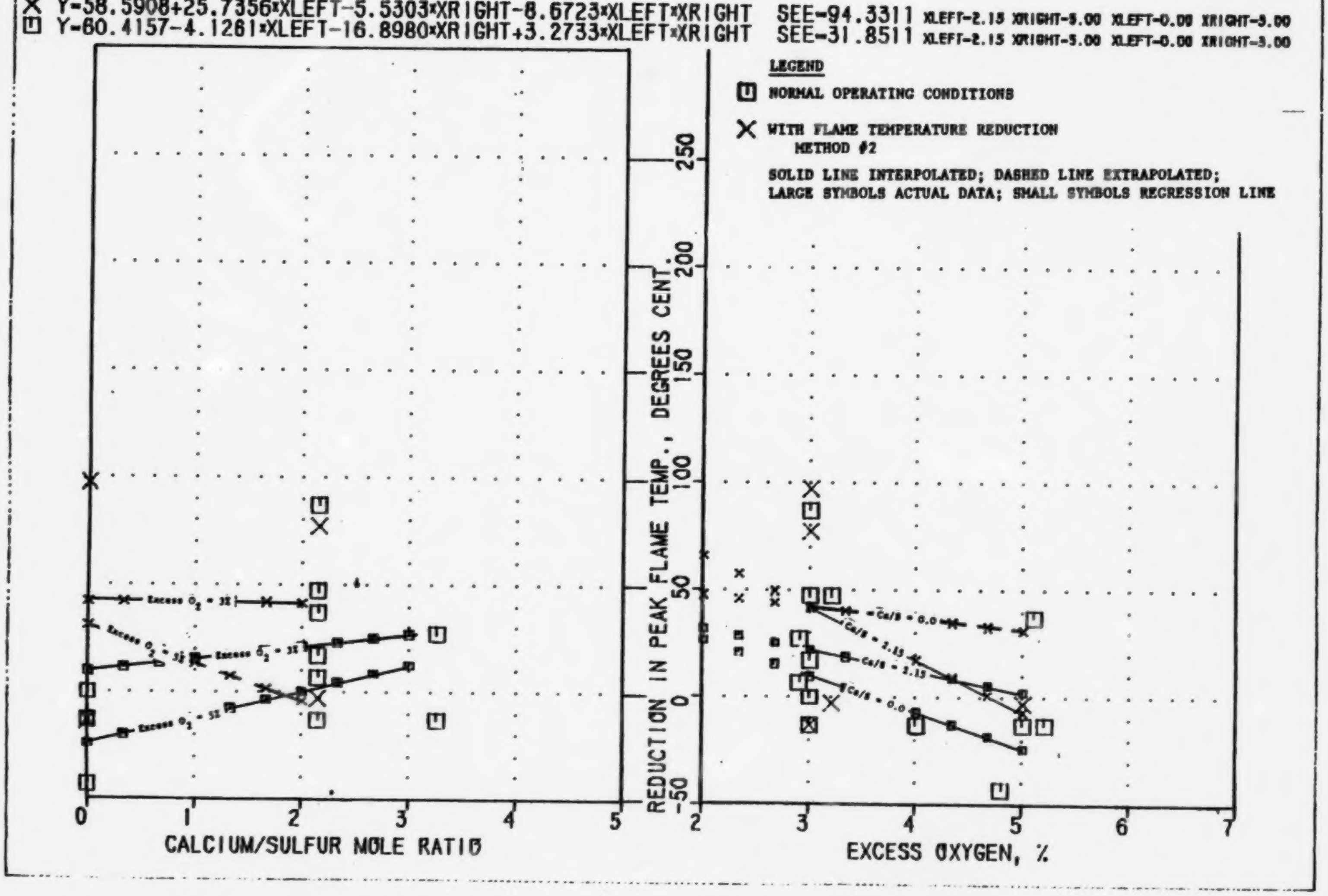

FIGURE 4.9: EFFECT OF EXCESS OXYGEN AND LIMESTONE ON PEAK FLAME TEMPERATURE

4.3 Effect of Overfire Air and Limestone

4.3.1 On SO_2 (Figure 4.10)

Under normal operating conditions the addition of OFA to the base case decreased the SO_2 reduction from 22% to 16% at 25% OFA at a Ca/S mole ratio of 2.15. SO_2 reduction decreased when 5% excess O_2 or FTRM #1 was combined with OFA. SO_2 reduction increased to 28% when FTRM #2 was combined with 20% OFA; 28% reduction was the average achieved with all tests with the combination of FTRM#2 and 20% OFA including 3 hour steady state tests 42 and 43. Test 42 and 43 are included such that each reading taken during test 42 and 43 are treated as a single test.

4.3.2 On SO_3 (Figure 4.11)

The effect of limestone addition to the fuel, at a Ca/S mole ratio of 2.15, on SO_3 concentration is to reduce it to a measured value of 8 ppm from 28 ppm; a 71% reduction. At a Ca/S mole ratio of 3.26 the SO_3 did not decrease further. When 20% OFA is used without limestone addition the SO_3 decreased from 28 ppm to 8 ppm, the same level as with Ca/S = 2.15. When OFA is combined with a Ca/S mole ratio of 2.15 the SO_3 remains at 8 ppm. Increasing the OFA ratio to 25% further reduced the SO_3 to 6-7 ppm.

At 5% excess O_2 the SO_3 increased to 69 ppm from 28 ppm, a 146% increase. When a Ca/S mole ratio of 2.15 was tested at 5% O_2 the SO_3 was reduced to 19 ppm. At 20% OFA and a Ca/S mole ratio of 2.15 the SO_3 was reduced to 11 ppm, a 42% reduction. The effect of OFA at high O_2 without limestone was not tested. The combination of 20% OFA and Ca/S = 2.15 at high O_2 still yields an SO_3 level 62% below the normal level of 28 ppm.

When FTRM #2 was tested at 3% O_2 the SO_3 increased to 38 ppm, a 36% increase above 28 ppm. When limestone was added at a Ca/S mole ratio of 2.15 the SO_3 was again reduced to 8 ppm, a 79%

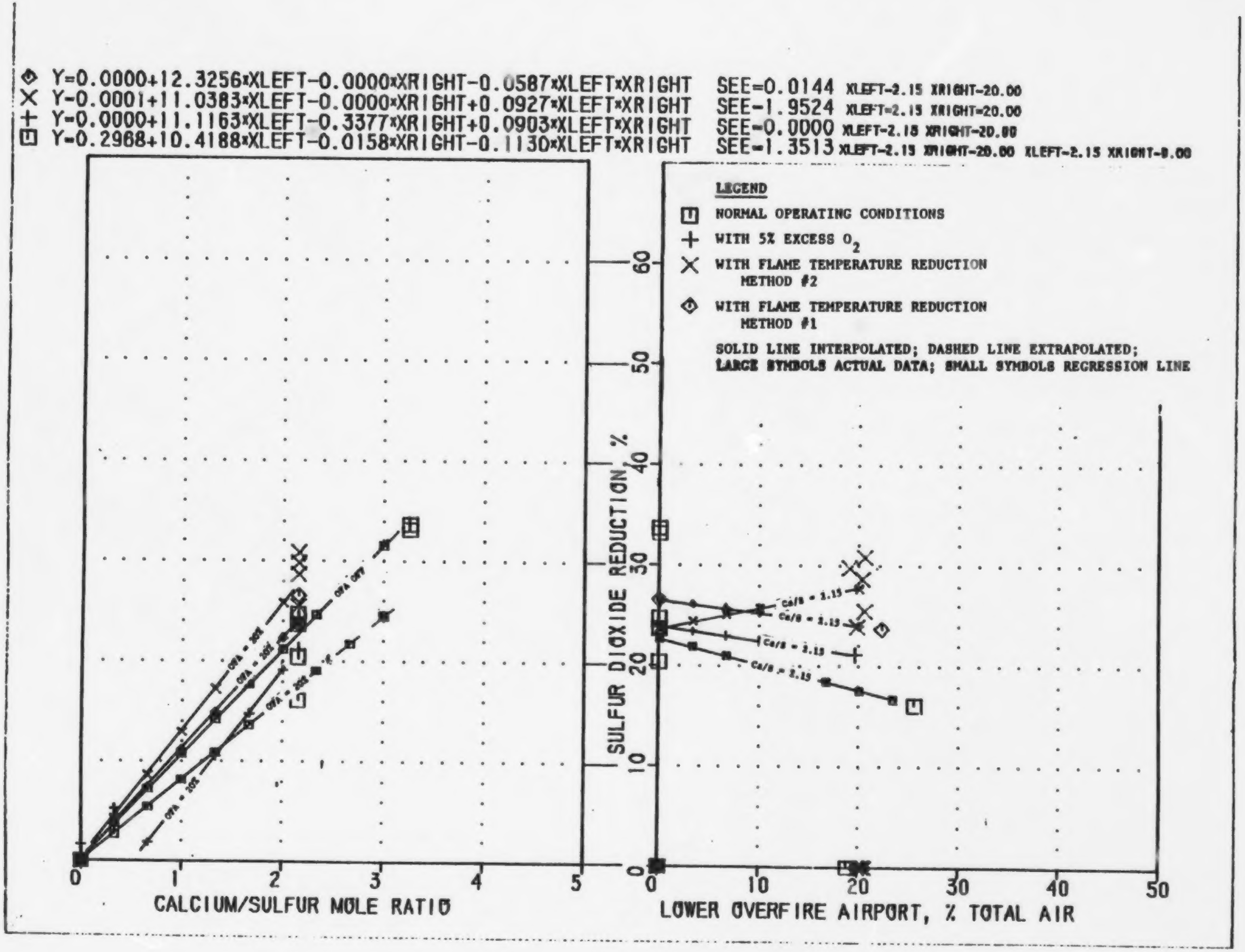

FIGURE 4.10: EFFECT OF OVERFIRE AIR AND LIMESTONE ON SULFUR DIOXIDE CONCENTRATIONS

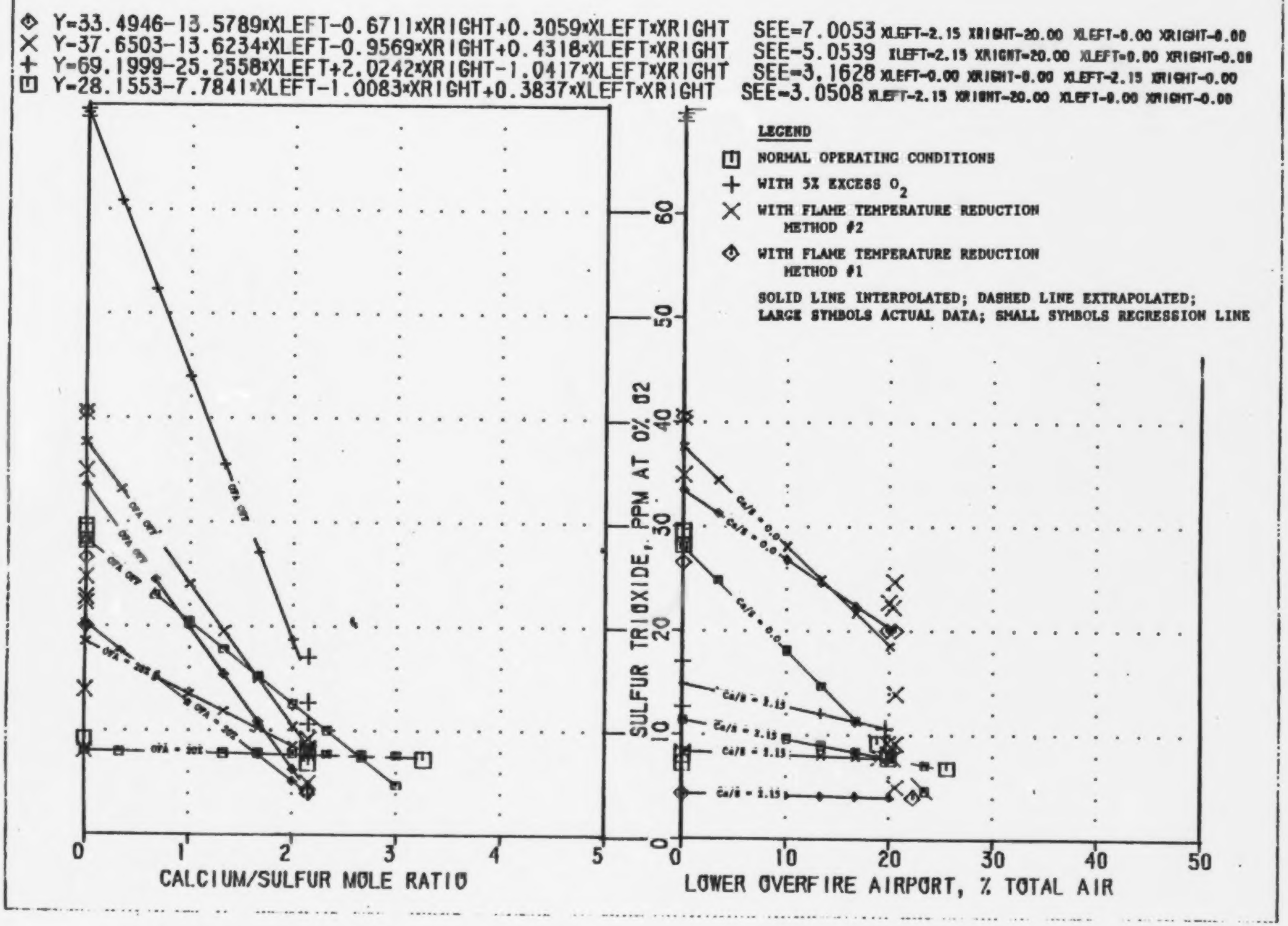

FIGURE 4.11: EFFECT OF OVERFIRE AIR AND LIMESTONE ON SULFUR TRIOXIDE CONCENTRATIONS

reduction. With 20% OFA added to FTRM #2, the SO_3 dropped to 18 ppm, without limestone, a 53% reduction. When FTRM #2, OFA and a Ca/S mole ratio of 2.15 are all combined the SO_3 returned to 8ppm. The combined effect did not reduce SO_3 further than just the combination of limestone and FTRM #2.

When FTRM #1 was tested the SO_3 increased from 28 ppm to 33 ppm. When limestone was added to the fuel at a Ca/S mole ratio of 2.15 in combination with FTRM #1 the SO_3 dropped to 4 ppm, an 88% reduction. When 20% OFA and FTRM #1 were combined the SO_3 dropped to 20 ppm. When all three are combined the SO_3 dropped to 4 ppm, an 86% reduction from 28 ppm. OFA did not decrease SO_3 further than the combination of FTRM #1 and limestone addition.

4.3.3 Effect on NO_x (Figure 4.12)

In general both limestone addition and OFA had a very consistent effect on the NO_x emission rate. The slope of the lines in Figure 4.12 are virtually identical, the only slope change occurs when 5% excess air is combined with limestone addition and OFA. When limestone is added to the fuel at a Ca/S of 2.15, the NO_x decreases from 0.32 lb/10^6Btu to 0.28 lb/10^6Btu, a 13% reduction. When the Ca/S mole ratio was increased to 3.26 the NO_x emission did not decrease further. When 20% OFA was used the NO_x decreased from 0.32 lb/10^6Btu to 0.23 lb/10^6Btu, a 27% reduction. When both OFA and limestone addition of a Ca/S of 2.15 are used the NO_x decreases from 0.32 to 0.21 lb/10^6Btu, a 34% reduction.

When the excess O_2 is increased to 5% the NO_x emission rate increased to 0.5 lb/10^6Btu. when limestone is added to the fuel at a Ca/S mole ratio of 2.15, the NO_x decreased by 0.04 lb/10^6Btu to 0.46 lb/10^6Btu an 8% decrease. When 20% OFA is used in combination with limestone addition at 5% excess O_2 , the NO_x decreased to 0.3 lb/10^6Btu from 0.45 lb/10^6Btu or a 33% reduction due to OFA.

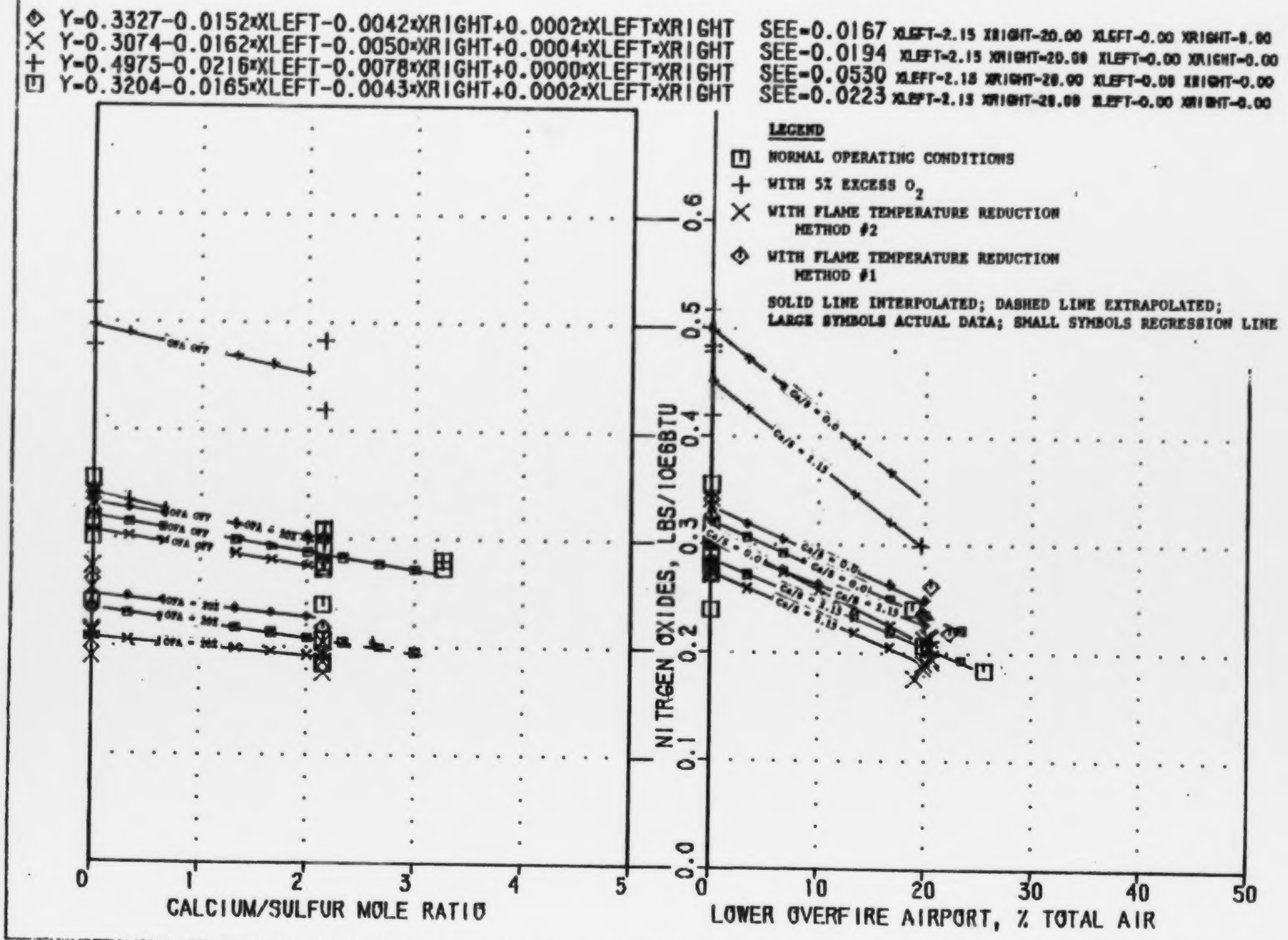

FIGURE 4.12: EFFECT OF OVERFIRE AND LIMESTONE ON NOx

When FTRM #2 was added the NO_x decreased to 0.31 lb/10^6Btu. The combination of FTRM #2 and limestone addition at a Ca/S mole ratio of 2.15 reduced the NO_x to 0.27 lb/10^6Btu, a 15% combined reduction. When FTRM #2 was combined with 20% OFA the NO_x went from 0.32 to 0.21, a 35% reduction. When FTRM #2, 20% OFA and a Ca/S mole ratio of 2.15 were combined the NO_x was reduced to 0.19 lb/10^6Btu a 41% reduction from 0.32 lb/10^6Btu.

When FTRM #1 was used the NO_x increased to 0.33 lb/10^6Btu. The combination of FTRM #1 and a Ca/S of 2.15 resulted in a NO_x of 0.3 lb/10^6Btu a reduction of 6% from 0.32 lb/10^6Btu. When FTRM #1 was combined with 20% OFA the NO_x was reduced to 0.25 lb/10^6Btu or a 22% reduction. The combination of all three reduced the NO_x to 0.22 lb/10^6Btu or a 30% reduction.

4.3.4 Effect on Carbon Monoxide (Figure 4.13)

The primary effect of addition of limestone to the fuel reduced the CO to below 35 ppm. The primary effect of the use of OFA increased CO to as high as 150 ppm. Under normal operating conditions the CO averaged 39 ppm. When limestone was added to the fuel at a Ca/S mole ratio of 2.15 the CO decreased to 13 ppm or a 67% reduction. When 20% OFA was added the CO increased to 147 ppm an increase of 380%. When 20% OFA and a Ca/S mole ratio of 2.15 were combined the CO decreased to 28 ppm or an 81% reduction. When the limestone addition rate was increased to a Ca/S mole ratio of 3.6 the CO was reduced to zero ppm.

When the excess O_2 was increased to 5% the CO decreased to 20 ppm, a 49% reduction from 39 ppm. When limestone at a Ca/S of 2.15 was combined with the 5% excess O_2 the CO decreased to 4 ppm, a 90% reduction from 39 ppm. When 20% OFA was combined with 5% excess O_2 the CO increased to 31 ppm from 20 ppm but this still is a 21% reduction from 39 ppm. When all three are combined the CO averaged 7 ppm an 82% reduction from 39 ppm.

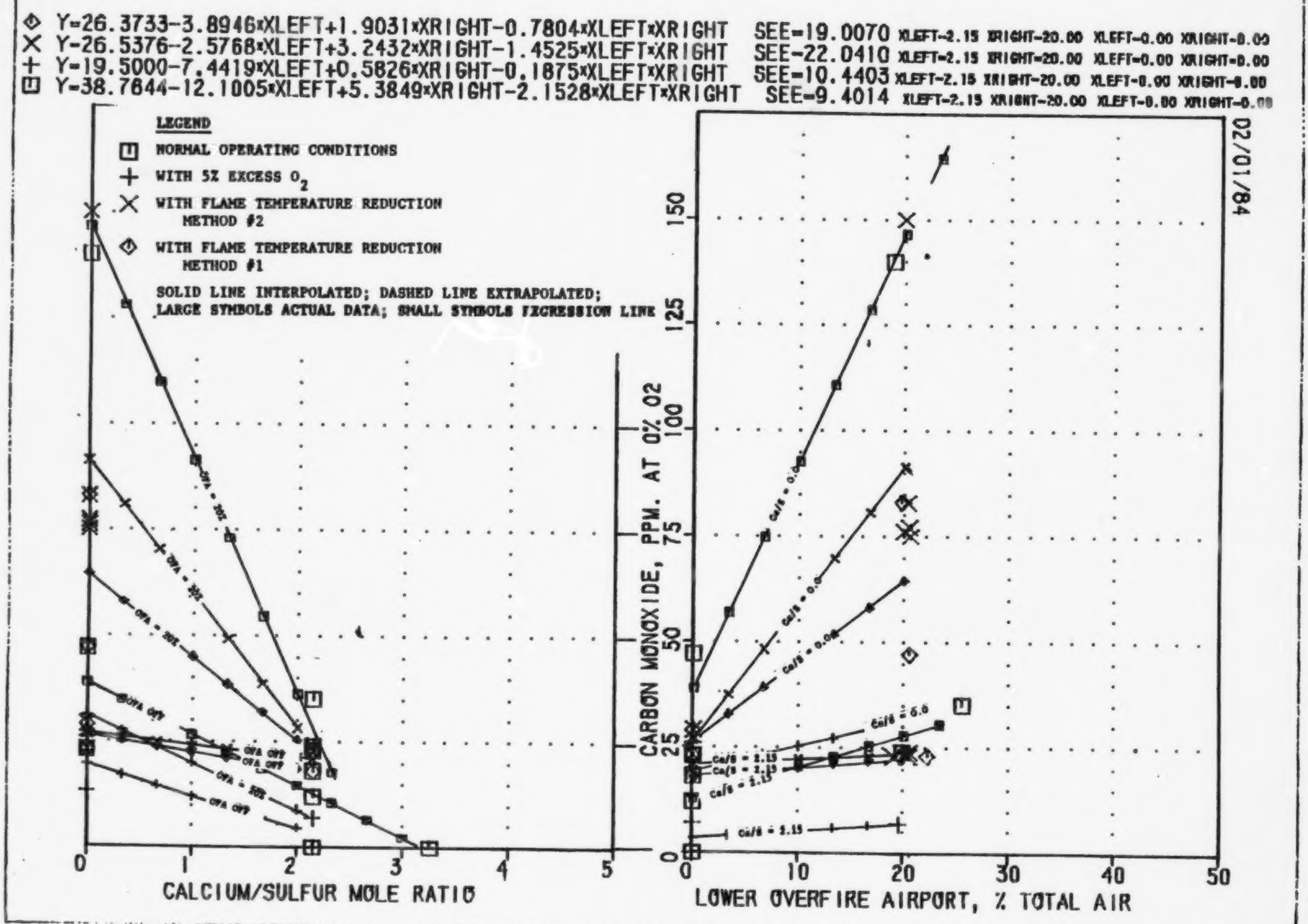

FIGURE 4.13: EFFECT OF OVERFIRE AIR AND LIMESTONE ON CARBON MONOXIDE

When FTRM #2 was added the CO decreased to an average of 27 ppm a 28% reduction from 39 ppm. When limestone was added at a Ca/S mole ratio of 2.15 in combination with FTRM #2 the CO decreased to 21 ppm a 22% reduction from 27 ppm. When 20% OFA is combined with FTRM #2 the CO increased to 91 ppm a 234% increase above 39 ppm. When all three effects are combined the CO decreased to 23 ppm a 40% reduction from 39 ppm.

When FTRM #1 was added to normal operating conditions the CO decreased to 26 ppm a 33% reduction from 39 ppm. When limestone was added to the fuel at a Ca/S mole ratio of 2.15 in combination with FTRM #1, the CO decreased to 18 ppm a 31 reduction from 21 ppm. When 20% OFA was combined with FTRM #1, the CO increased to 64 ppm a 164% increase in CO over 26 ppm. When all three effects are combined the CO dropped to 22 ppm a 45% decrease from the 39 ppm base level.

4.3.5 Effect on Total Hydrocarbons (Figure 4.14)

In general the addition of limestone to the fuel at a Ca/S mole ratio of 2.15 decreased the THC. The effect of OFA is not consistent: in some cases it increases THC, in some cases it decreases THC. Under normal operating conditions the addition of limestone at a Ca/S of 2.15 decreases THC from 3 ppm to 2 ppm a 33% decrease. A further increase in Ca/S to 3.26 decreased the THC to 1.6 ppm a 47% decrease from 3 ppm. When both 20% OFA and a Ca/S of 2.15 are combined the THC increased to 3.6 ppm a 20% increase over 3 ppm.

When the excess O_2 was increased to 5% the THC increased to 12.7 ppm a 323% increase over 3 ppm. This was unexpected. When limestone was added at a Ca/S of 2.15 and at 5% excess O_2 the THC decreased to 2.9 ppm, a 77% decrease from 12.7 ppm. When 20% OFA was added to a Ca/S of 2.15 and 5% excess O_2 the THC increased to 3.2 ppm.

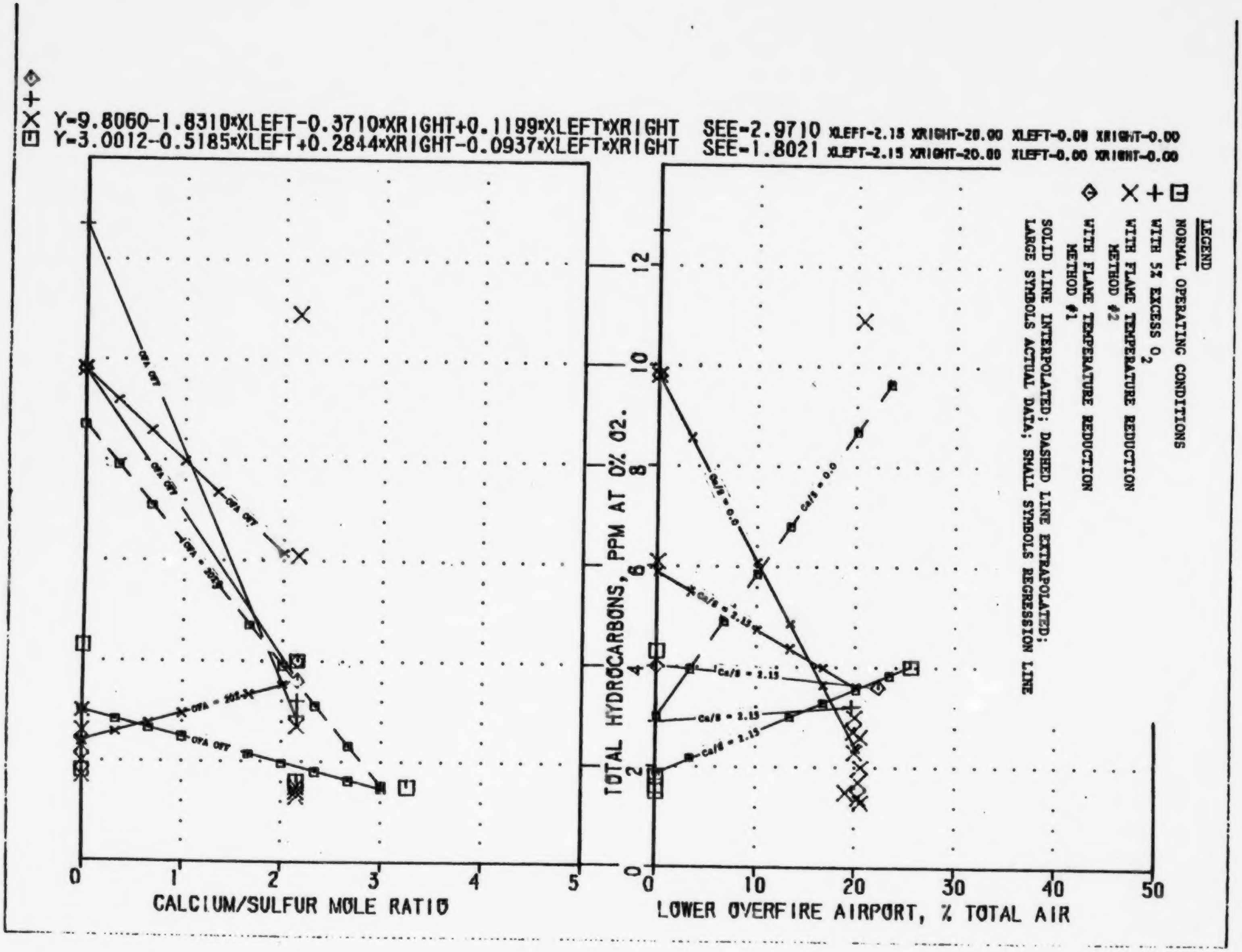

FIGURE 4.14: EFFECT OF OVERFIRE AIR AND LIMESTONE ON TOTAL HYDROCARBONS

When FTRM #2 was used the THC increased to an average of 9.8 ppm, a 227% increase above 3 ppm. When limestone was added at a Ca/S mole ratio of 2.15 to FTRM #2 the THC decreased to 6 ppm, but this still represented a 100% increase over 3 ppm. When 20% OFA was combined with FTRM #2 the THC decreased to 3.6 ppm still 20% higher than 3 ppm. When all three effects are combined the THC decreased to 2.4 ppm a 20% decrease from 3 ppm.

When FTRM #1 was used the THC increased to 9.3 ppm a 227% increase above 3 ppm. When limestone was added at a Ca/S mole ratio of 2.15 and combined with FTRM #1, the THC decreased to 4 ppm but this still represents a 33% increase over 3 ppm. When 20% OFA is combined with FTRM #1 and Ca/S of 2.15 the THC decreased to 3.6 ppm, still a 20% increase over 3 ppm.

4.3.6 Effect on Peak Flame Temperature (Figure 4.15)

In most cases the addition of limestone or the use of OFA decreased the peak flame temperatures (PFT). Under normal operating conditions increasing the limestone addition rate to a Ca/S mole ratio of 2.15 reduced the peak flame temperature by an average of 25°C (45°F). Increasing the Ca/S mole ratio to 3.26 reduced the PFT by an average of 35°C (63°F). When 20% OFA was used the PFT was reduced 50°C (90°F). The combination of OFA and a Ca/S of 2.15 reduced the PFT by 50°C (90°F).

When the excess O_2 was increased to 5% the PFT increased by an average of 25°C (45°F). When limestone was added at a Ca/S of 2.15 in combination with 5% O_2 the PFT was reduced by 12°C (22°F). When 5% excess O_2, Ca/S of 2.15 and OFA at 20% were combined the net result is a 34°C (61°F) increase in PFT.

When FTRM #2 is used the PFT is reduced an average of 42°C (76°F). When FTRM #2 is combined with a Ca/S of 2.15 the PFT is reduced by 35°C (64°F). When FTRM #2 is combined with 20% OFA the PFT

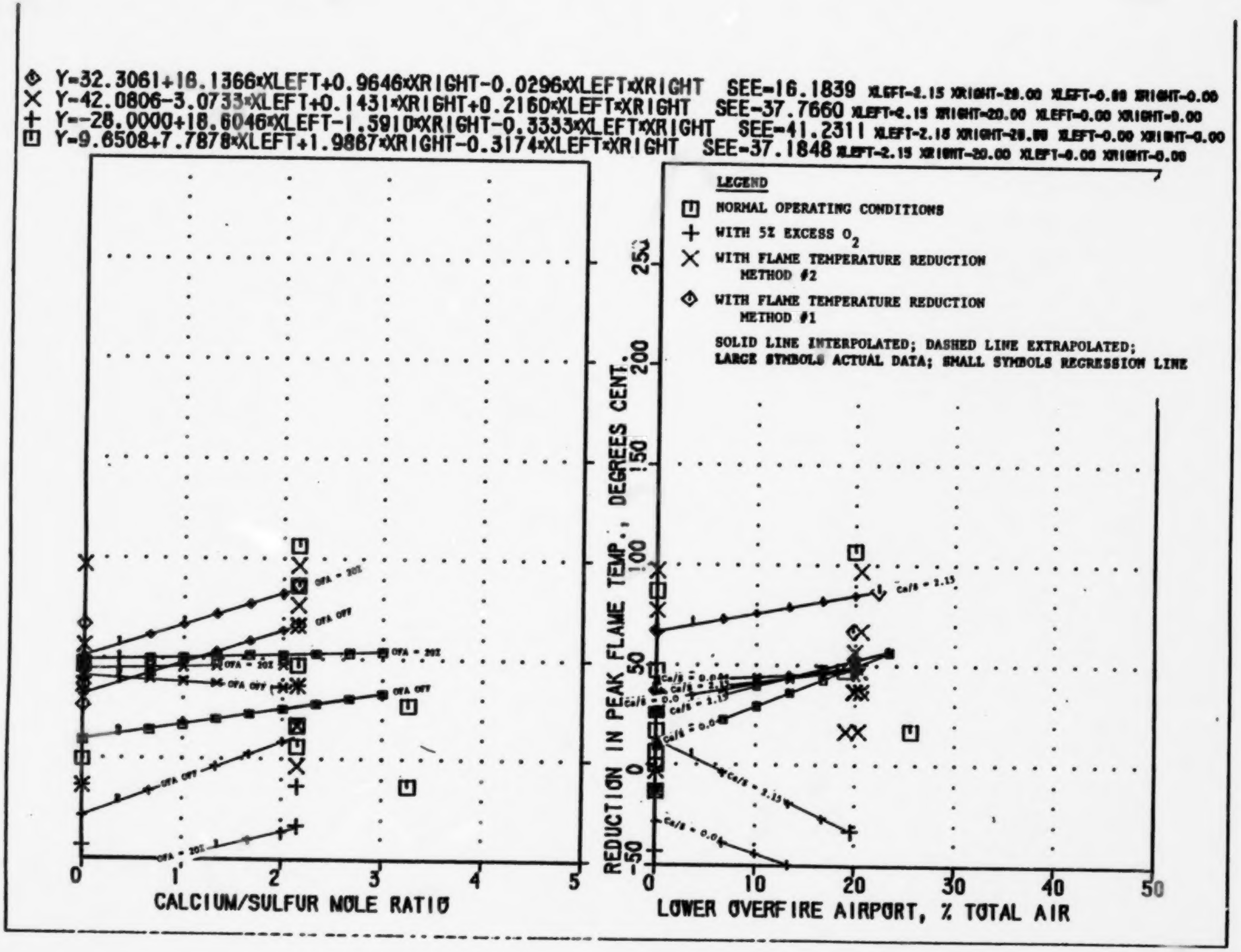

FIGURE 4.15: EFFECT OF OVERFIRE AIR AND LIMESTONE ON PEAK FLAME TEMPERATURE

is reduced by 45°C (81°F). When all three effects are combined the PFT is reduced by 47°C (86°F).

When FTRM #1 is used the PFT is reduced an average of 32°C (58°F). When FTRM #1 is combined with a Ca/S of 2.15 the PFT is reduced an average of 67°C (121°F). When FTRM #1 is combined with 20% OFA the PFT is reduced an average of 52°C (94°F). When all three effects are combined the average PFT reduction is 85°C (153°F).

4.4 Effect of Flame Temperature Reduction Method #1 and Limestone

4.4.1 On SO_2 (Figure 4.16)

Under normal operating conditions the average SO_2 reduction was 22.7% at Ca/S = 2.15. When FTRM #1 was used the reduction increased to 26.5%. When OFA was used in combination with FTRM #1 the SO_2 reduction was 23.8%.

4.4.2 On SO_3 (Figure 4.17)

Under normal operating conditions the SO_3 concentration was an average of 28 ppm. When FTRM #1 was added the SO_3 increased 5 ppm to 33 ppm an 18% increase. When the limestone was added at a Ca/S of 2.15 the SO_3 dropped to 11 ppm a 61% reduction. When both FTRM #1 and limestone addition at a Ca/S of 2.15 were combined the SO_3 dropped to 4 ppm an 85% reduction.

When FTRM #2 was used the SO_3 increased to 38 ppm a 36% increase over 28 ppm. When both FTRM #1 and #2 were combined the SO_3 dropped to 20 ppm a 29% decrease from 28 ppm.

The effect of the combination of OFA and FTRM #1 was discussd fully in Section 4.3.2 it is shown in Figure 4.17 for comparison.

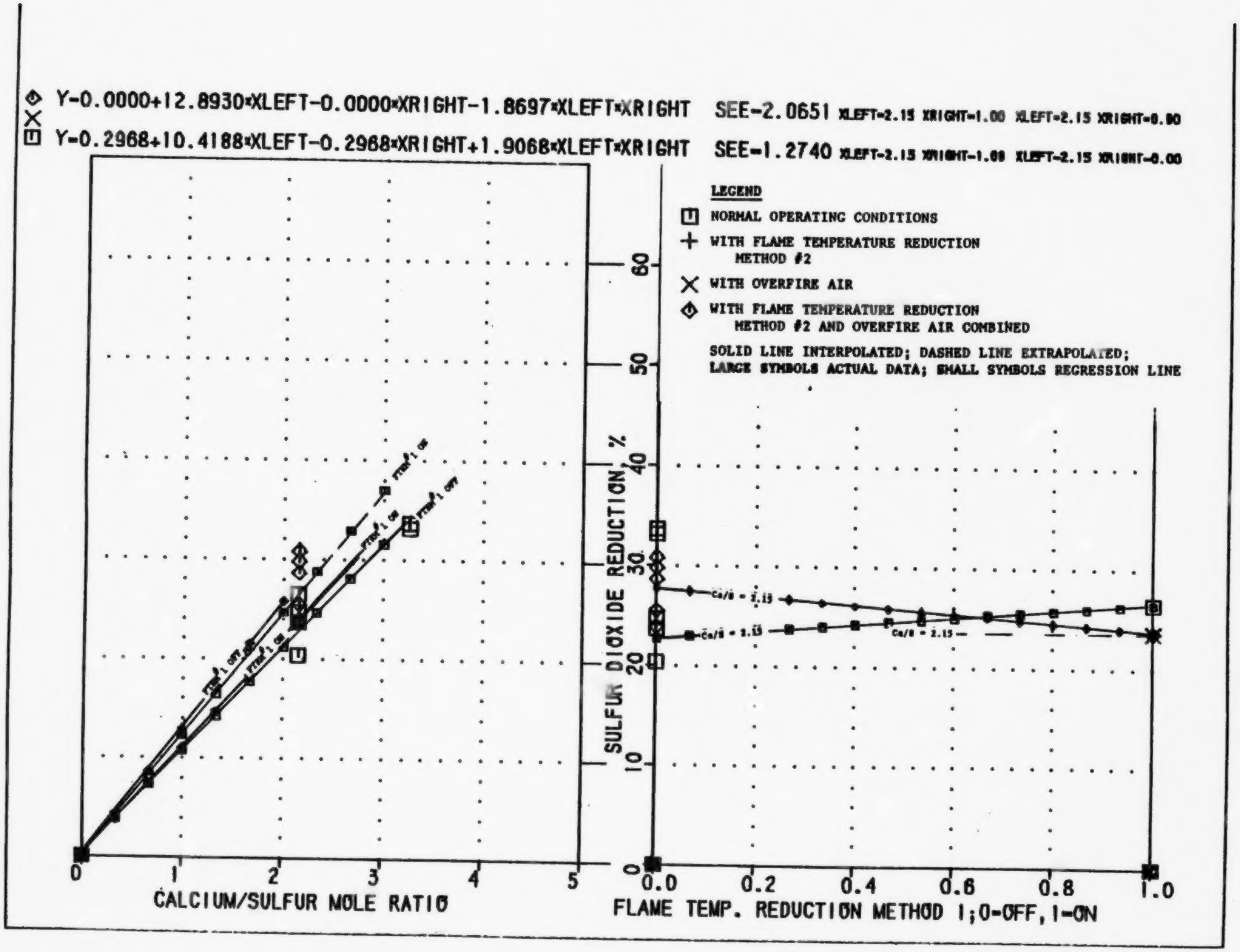

FIGURE 4.16: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #1 AND LIMESTONE ON SULFUR DIOXIDE REDUCTION

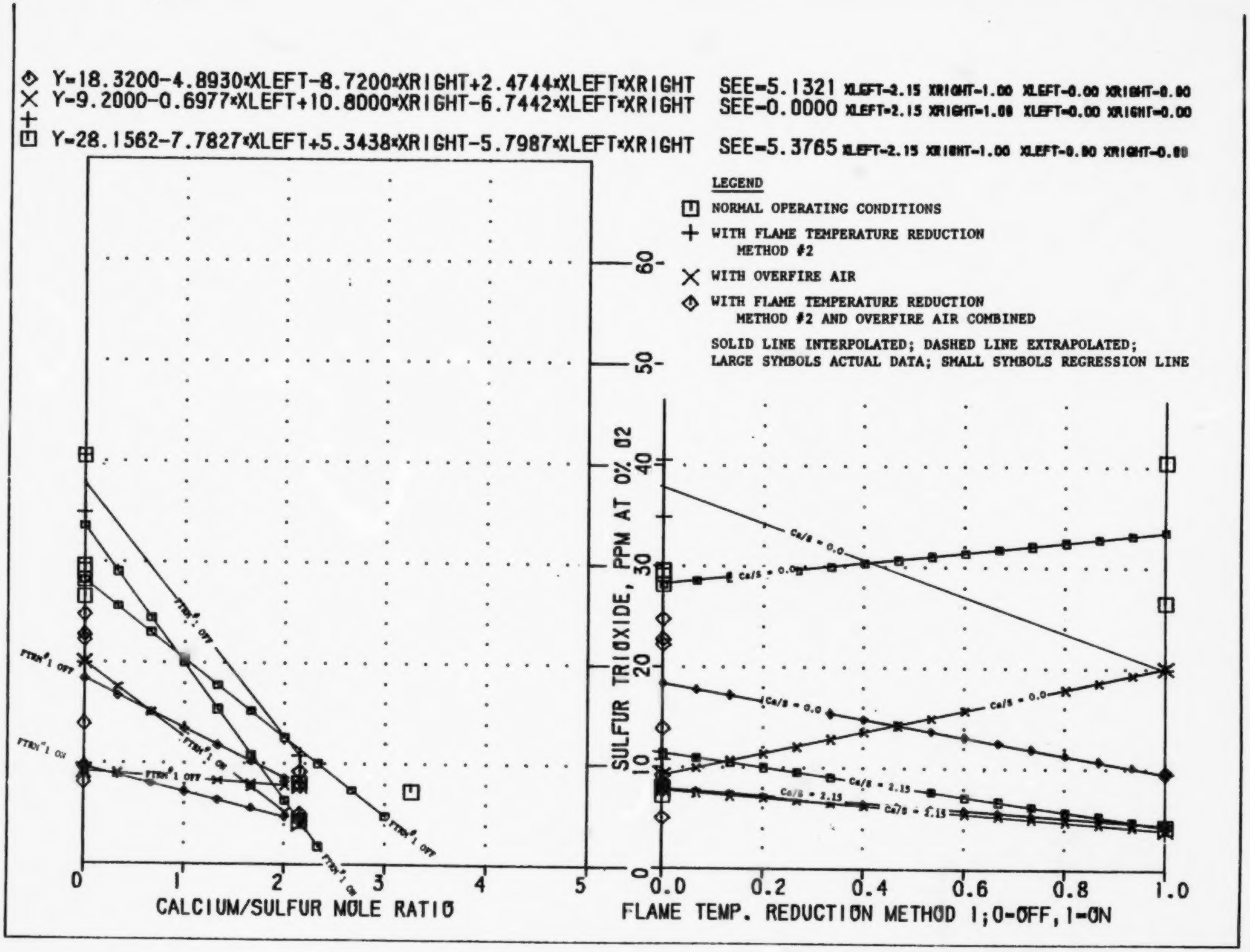

FIGURE 4.17: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #1 AND LIMESTONE ON SULFUR TRIOXIDE

When both FTRM #2 and OFA are combined the SO_3 measured an average of 18 ppm, a 36% reduction from 28 ppm. When limestone was added to the fuel at a Ca/S mole ratio of 2.15 in combination with FTRM #2 and OFA the SO_3 dropped to 7 ppm, a 75% reduction from 28 ppm. When FTRM #1 and 2 and OFA were combined the SO_3 dropped to 10 ppm, a 64% reduction from 28 ppm. When all three were combined with limestone addition at a Ca/S mole ratio of 2.15 the SO_3 dropped to 4 ppm, an 86% reduction from 28 ppm.

4.4.3 On NO_x (Figure 4.18)

As discussed in Section 4.3.3 NO_x emissions responded consistently to limestone addition and OFA and in this case FTRM #1 also. The only exception was in combination with FTRM #2. When FTRM #2 was used the NO_x decreased to 0.31 lb/10^6Btu from 0.32 lb/10^6Btu a 3% reduction, but when limestone was added to this combination the NO_x returned to 0.32 lb/10^6Btu. In a similar manner when FTRM #1 and #2 were combined the NO_x increased 13% to 0.35 lb/10^6Btu. But when limestone was added at a Ca/s of 2.15 to this combination of FTRM #1 and #2 the NO_x decreased to 0.3 lb/10^6Btu

The effect of the combination of OFA and FTRM #1 on NO_x are discussed in Section 4.3.3. The results are shown here for comparison.

When both FTRM #2 and OFA at 20% are used the NO_x decreased to 0.21 lb/10^6Btu, a 34% reduction from 0.32 lb/10^6Btu was achieved. When limestone was added at a Ca/S of 2.15 the NO_x decreased to 0.19 lb/10^6Btu, a 41% reduction from 0.32 lb/10^6Btu was achieved. When FTRM #2 and #1, OFA at 20% and limestone at Ca/S = 2.15 are all used together the NO_x level was 0.20 lb/10^6Btu, but this was still a 37% reduction from 0.32 lb/10^6Btu.

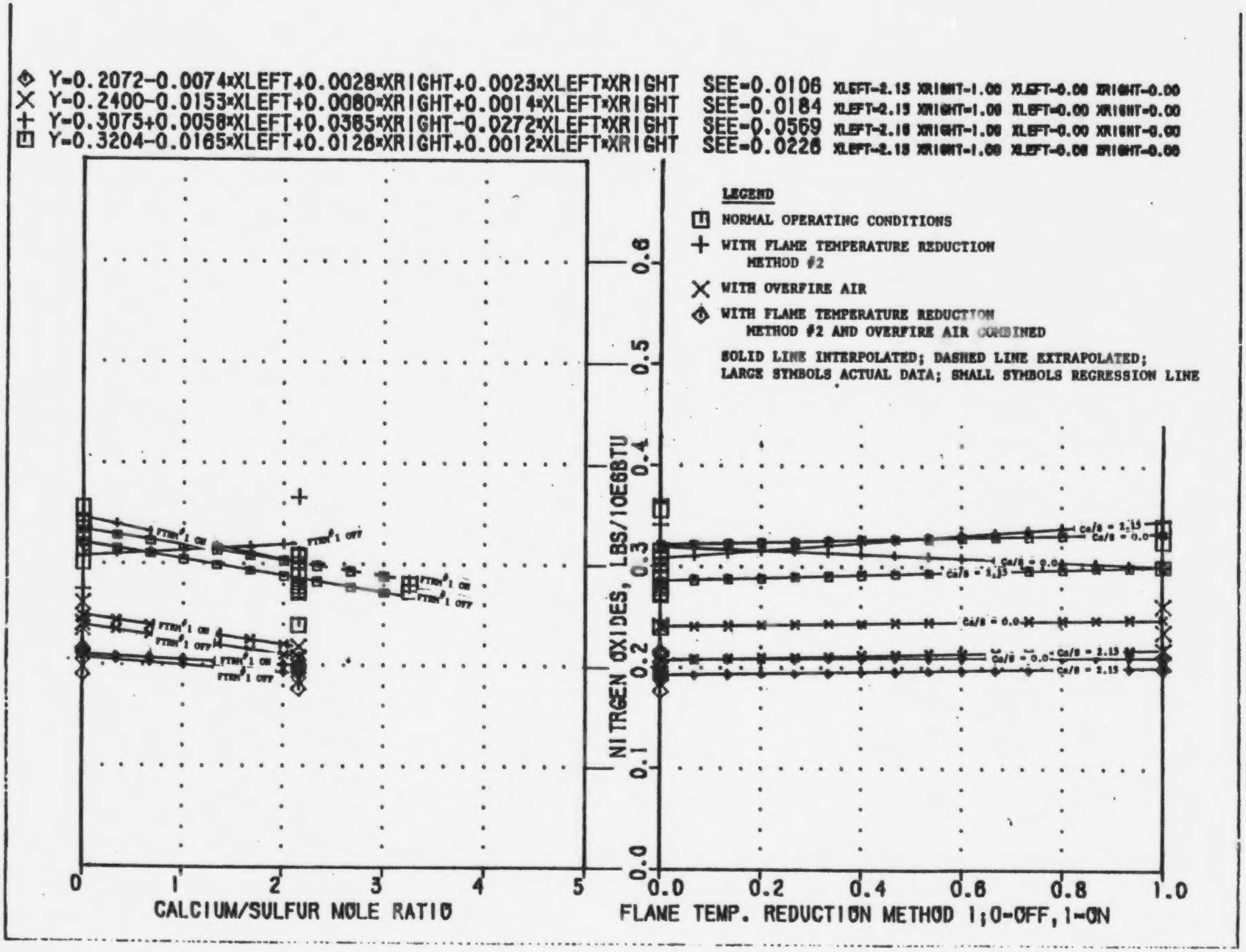

FIGURE 4.18: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #1 AND LIMESTONE ON NOx

4.4.4 On Carbon Monoxide (Figure 4.19)

In every combination that was tested as shown in Figure 4.19 when the limestone was added at a Ca/S mole ratio of 2.15 or higher the CO decreased to below 25 ppm. FTRM #1 had in general no consistent effect on CO. Under normal operating conditions the CO average was 39 ppm. When limestone was added at a Ca/S of 2.15, the CO decreased to 13 ppm, a 67% reduction. When FTRM #1 was used the CO decreased from 39 ppm to 26 ppm a 33% reduction. When both FTRM #1 and limestone addition were combined the CO decreased to 18 ppm a 55% reduction from 39 ppm.

When FTRM #2 was used the CO decreased to 26 ppm, a 33% reduction from 39 ppm. In combination with limestone at a Ca/S of 2.15 the CO decreased to 11 ppm, a 72% reduction from 39 pm. When FTRM #1 and #2 were combined with limestone addition at a Ca/S of 2.15 the CO increased to 18 ppm, this reduction is still a reduction of 54% from 39 ppm.

The effect of OFA in combination with FTRM #1 was fully discussed in Section 4.3.4. It is shown here for comparison purposes.

When both FTRM #2 and OFA are used the CO increased to 92 ppm primarily because of the effect of OFA on CO, this is a 136% increase in CO above 39 ppm. When limestone is added at a Ca/S of 2.15 in combination with FTRM #2 and OFA both with and without FTRM #1, the CO decreases to 23 ppm, a 41% reduction from 39 ppm.

4.4.5 On Total Hydrocarbons (Figure 4.20)

Under normal operating conditions the THC measured an average of 3 ppm. When limestone was added at a Ca/S of 2.15 the THC dropped to 2 ppm a 33% decrease. When FTRM #1 was used the THC

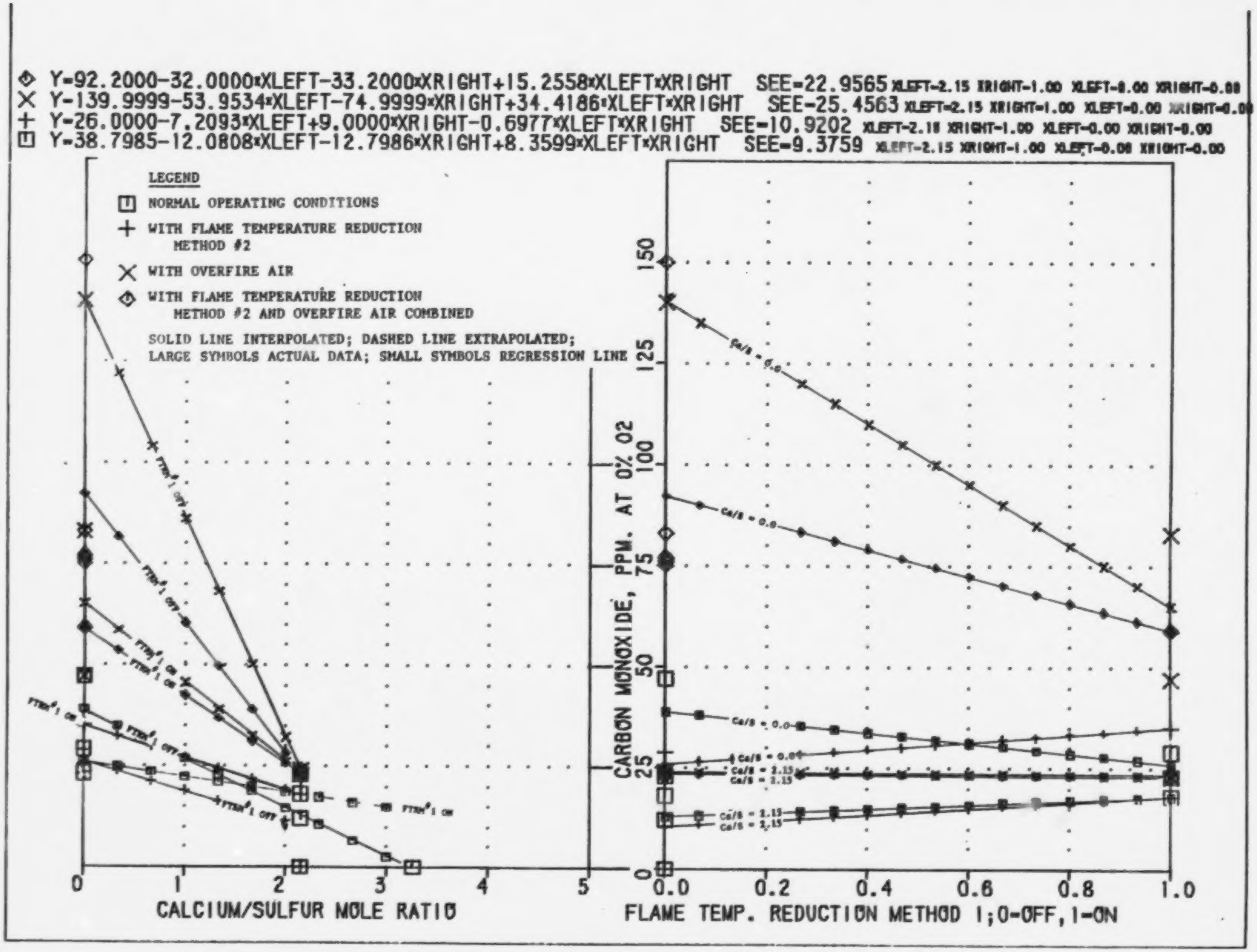

FIGURE 4.19: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #1 AND LIMESTONE ON CARBON MONOXIDE

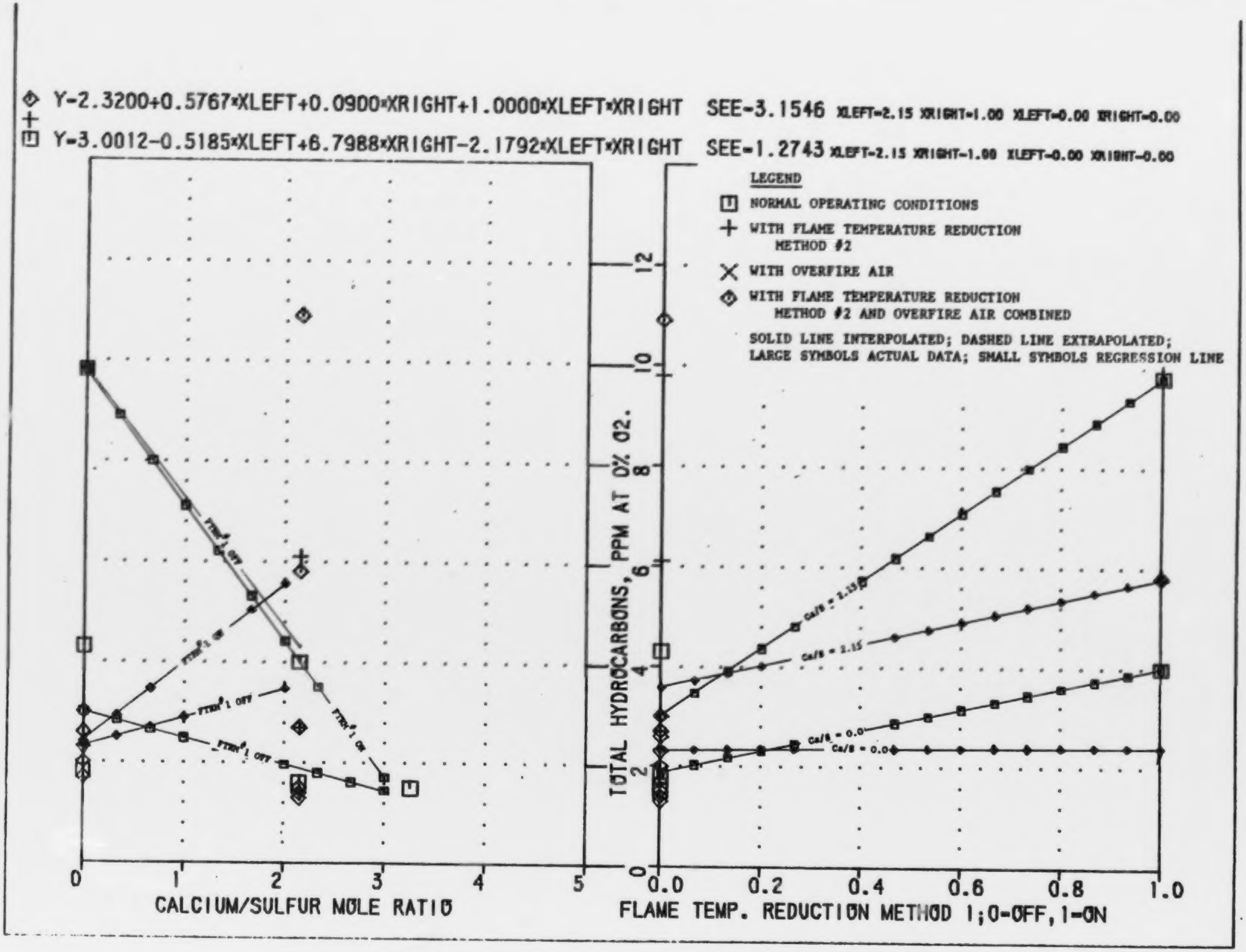

FIGURE 4.20: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #1 AND LIMESTONE ON TOTAL HYDROCARBONS

increased to 9.8 ppm a 227% increase. When limestone addition and FTRM #1 were combined the THC dropped to 4 ppm, a 33% increase over 3 ppm.

The effect of FTRM #2 and limestone addition at a Ca/S of 2.15 is shown in Figure 4.20 for comparison. The tests of this in combination with FTRM #1 did not have valid THC measurements.

The effect of OFA and FTRM #1 did not have valid THC measurements and are not shown.

The combination of FTRM #2 and OFA at 20% decreased the measured THC to 2.3 ppm a 23% reduction from 3 ppm. When limestone at a Ca/S mole ratio of 2.15 is added the THC increased to 3.5 ppm, an 18% increase above 3 ppm. When OFA at 20% and both FTRM #1 and #2 are combined the THC does not change from 2.3 ppm, but when limestone addition is added to this combination at a Ca/S of 2.15 the THC increases to 5.9 ppm a 97% increase above 3 ppm.

4.4.6 On Peak Flame Temperature (Figure 4.21)

Under normal operating conditions the PFT is reduced 32°C (58°F) when FTRM #1 is used. When the FTRM #1 is combined with limestone addition at a Ca/S of 2.15 the PFT is reduced 69°C (124°F). When limestone was added by itself the PFT was reduced 25°C (45°F).

When FTRM #2 is used the PFT is reduced 42°C (76°) from normal operating conditions. When FTRM #2 is combined with FTRM #1 the PFT reduction is 87°C (157°F). When FTRM #1 and #2 is combined with limestone addition at Ca/S of 2.15 the PFT is reduced by 146°C (263°F).

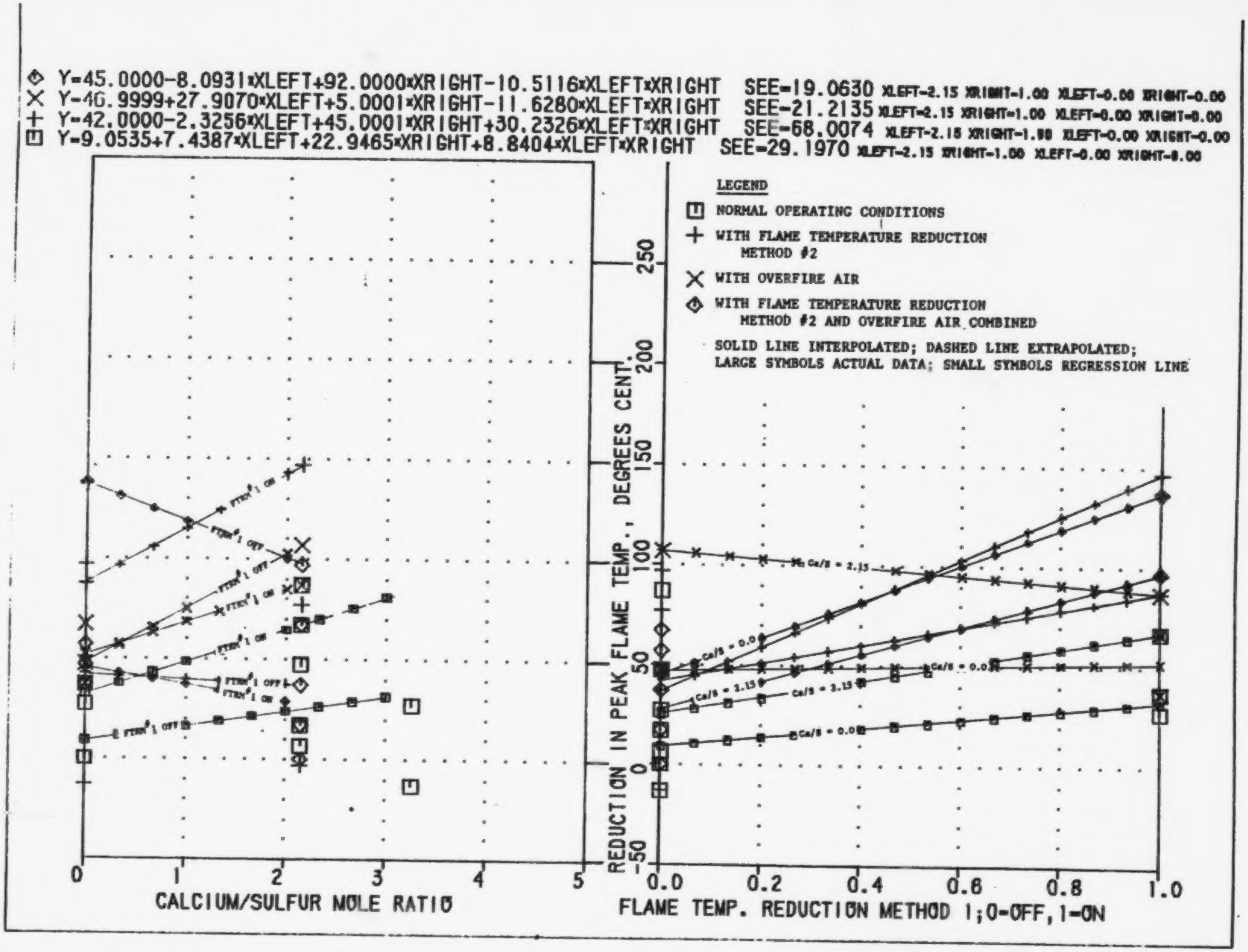

FIGURE 4.21: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #1 AND LIMESTONE ON PEAK FLAME TEMPERATURE

The combination of OFA and FTRM #1 was discussed in Section 4.3.6 it is shown here for comparison.

When FTRM #2 and OFA at 20% were combined the PFT was reduced by 47°C (85°F). When these two were combined with limestone addition at a Ca/S of 2.15 the PFT was reduced 106°C (191°F). This case represents the optimum SO_2 reduction test condition. The combination of these 3 methods with FTRM #1 resulted in a PFT reduction of only 86°C (155°F). When FTRM #1 and #2 were tested with OFA at 28% the PFT was reduced by 52°C (94°F).

4.5 Effect of Flame Temperature Reduction Method #2 and Limestone

4.5.1 On SO_2 (Figure 4.22)

Under normal operating conditions the addition of limestone at a Ca/S mole ratio of 2.15 results in an SO_2 reduction of 22.7%. When FTRM #2 is used the SO_2 reduction increases to 23.8%. When FTRM #2 is combined with OFA at 20% the SO_2 reduction increases to 29%. When FTRM #2 is combined with 5% excess O_2 the SO_2 reduction increases to 31.4% reduction; slightly less than the 33% achieved by increasing the Ca/S mole ratio to 3.26.

4.5.2 On SO_3 (Figure 4.23)

In general, the addition of limestone to the fuel at a Ca/S mole ratio of 2.15 decreased the SO_3 to less than 17 ppm. The use of FTRM #2 in many combinations with other effects decreased SO_3 but there were some combinations where it increased. Under normal operating conditions the addition of limestone at a Ca/S of 2.15 decreased the SO_3 to 11 ppm, a 60% decrease from normal 28 ppm. The use of FTRM #2 resulted in an increase in SO_3 to 38 ppm, a 36% increase above 28 ppm. When limestone addition and FTRM #2 are combined the SO_3 decreases to 10 ppm, a 64% decrease below 28 ppm.

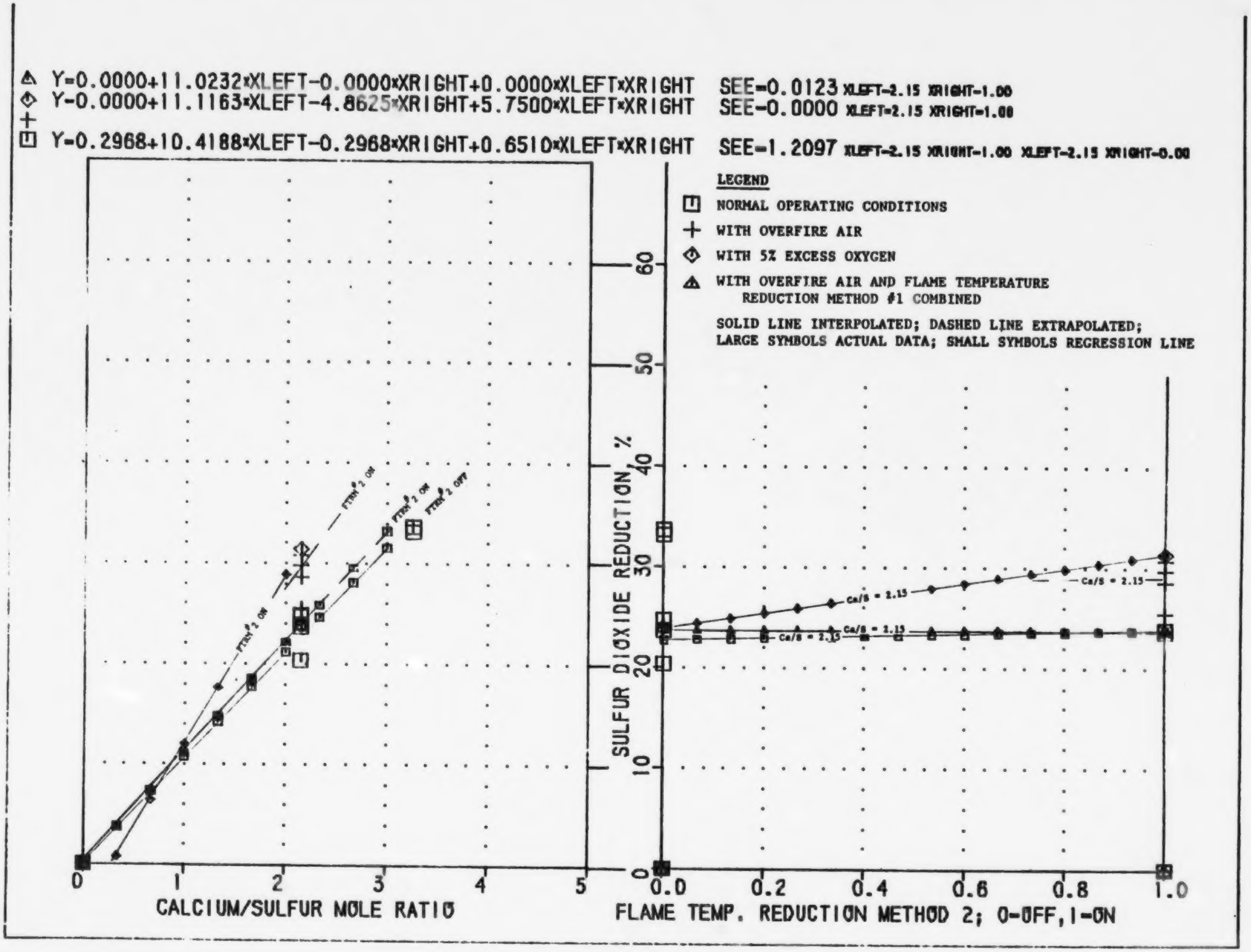

FIGURE 4.22: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #2 AND LIMESTONE ON SULFUR DIOXIDE REDUCTION

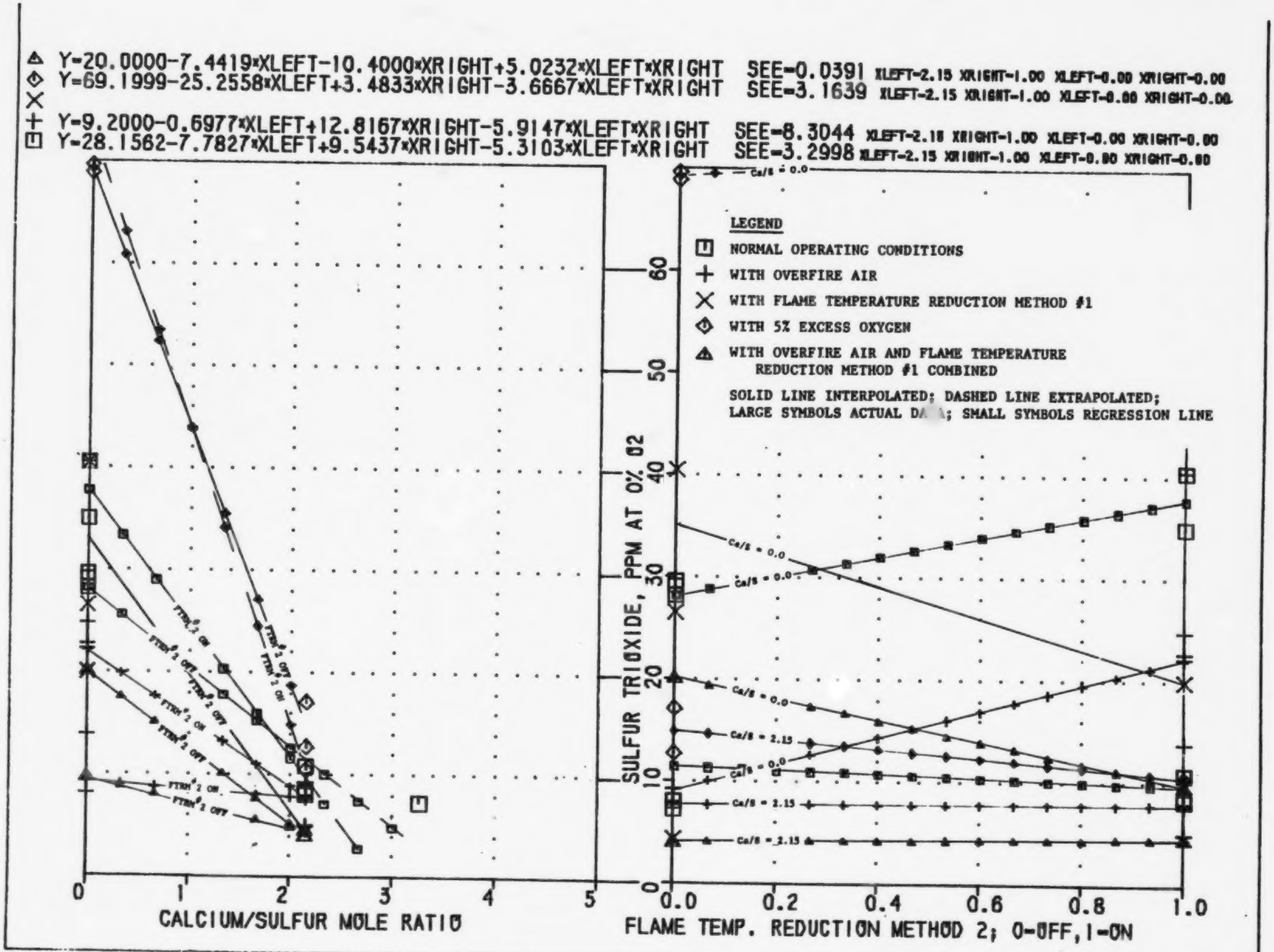

FIGURE 4.23: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #2 AND LIMESTONE ON SO3

The effect of the combination of OFA with FTRM #2 is discussed in Section 4.3.2. It is shown in Figure 4.23 for comparison purposes.

The effect of the combination of FTRM #2 with FTRM #1 and the effect of FTRM #2 with FTRM #1 and OFA is discussed in Section 4.4.2. It is shown in Figure 4.23 for comparison purposes.

The effect of the combination of FTRM #2 with 5% excess O_2 is discussed in Section 4.2.2. It is shown in Figure 4.23 for comparison purposes.

4.5.3 On NO_x (Figure 4.24)

Under normal operating conditions the NO_x emission rate is 0.32 $lb/10^6Btu$. The addition of limestone at a Ca/S mole ratio of 2.15 results in a decrease in NO_x to 0.28 $lb/10^6Btu$, a 13% decrease. The use of FTRM #2 results in a decrease in NO_x to 0.31 $lb/10^6Btu$, a 3% decrease. When both limestone addition and FTRM #2 are combined the NO_x emissions are 0.32 $lb/10^6Btu$, no change from normal operating conditions.

The effect of combinations of FTRM #2 with other operating variables on NO_x is discussed in previous sections notably sections 4.3.3, 4.4.3 and 4.2.3. These comparisons are shown in Figure 4.24 to show the complete picture of the effect of FTRM #2 on NO_x.

4.5.4 On Carbon Monoxide (Figure 4.25)

Under normal operating conditions the average CO concentration at the economizer outlet is 39 ppm. When limestone is added at a Ca/S mole ratio of 2.15 the CO drops to an average of 13 ppm, a 67% reduction. When FTRM #2 is used the CO concentration drops to 26 ppm, a 33% reduction. When both FTRM #2 and limestone addition are combined the CO drops to 10 ppm, a 75% reduction in CO.

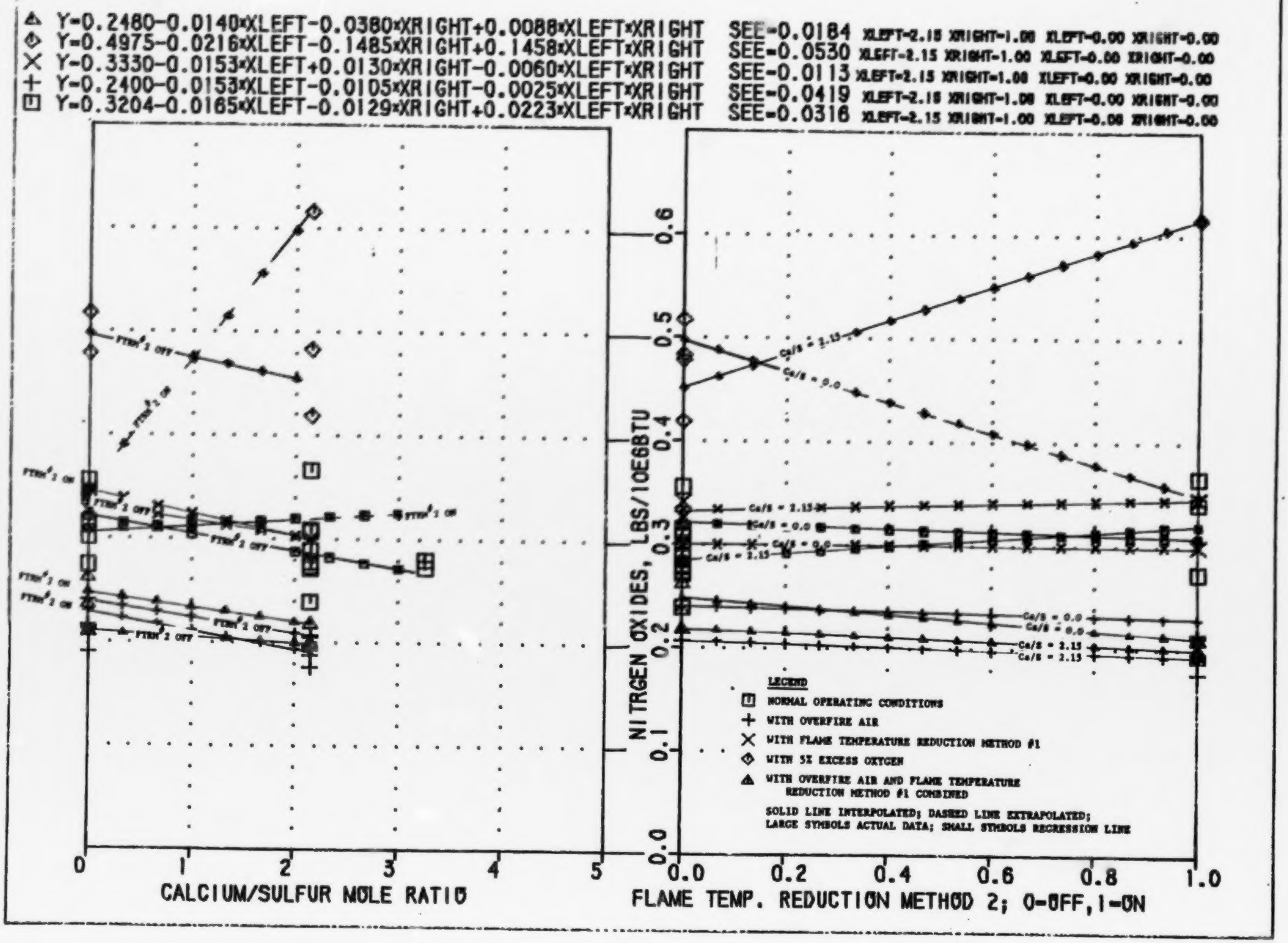

FIGURE 4.24: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #2 AND LIMESTONE ON NOx

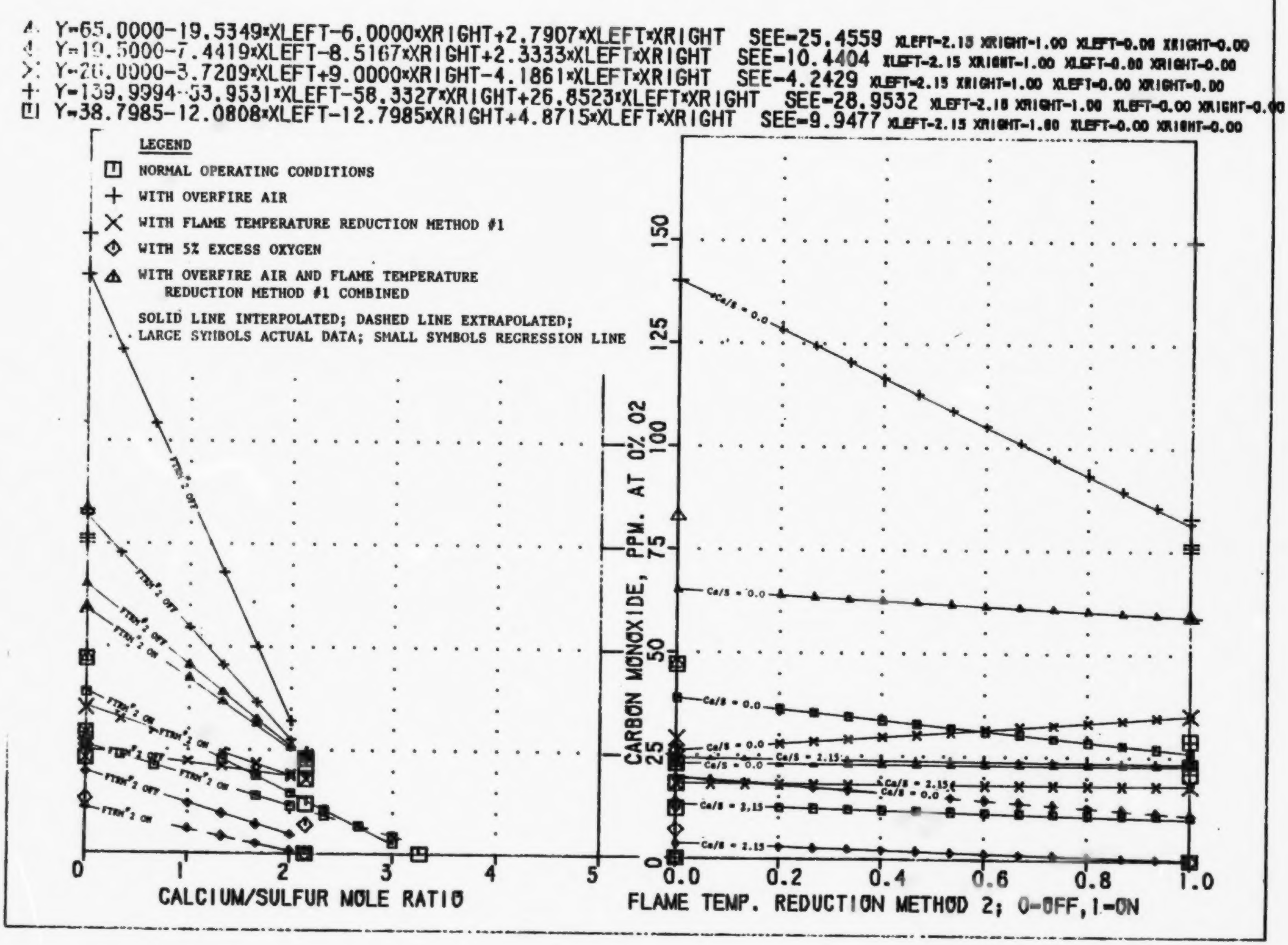

FIGURE 4.25: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #2 AND LIMESTONE ON CARBON MONOXIDE

The effect of the combination of FTRM #2 with other operating variables on CO is discussed in previous sections notably sections 4.3.4, 4.4.4 and 4.2.4. These comparisons are shown in Figure 29 to show the complete picture of the effect of FTRM #2 on CO.

4.5.5 On Total Hydrocarbons (Figure 4.26)

Under normal operating conditions the THC concentration is 3 ppm. When limestone is added to the fuel at a Ca/S of 2.15 the THC drops to 2 ppm, a 33% reduction. When FTRM #2 is used the THC concentration increases to 9.8 ppm, a 227% increase. When both are used together the THC increases only to 4.4 ppm, a 47% increase.

The effect of the combination of FTRM #2 with other operating variables on THC is discussed in previous sections, notably Sections 4.3.5, 4.4.5 and 4.2.5. These comparisons are shown in Figure 4.26 to show the complete picture of the effect of FTRM #2 on THC.

4.5.6 On Peak Flame Temperature (Figure 4.27)

When FTRM #2 is used the PFT is reduced an average of 42°C (76°F). When limestone is added to the fuel the PFT is reduced by 25°C (45°F). When both FTRM #2 and limestone addition are combined the PFT is reduced by 37°C (67°F). The effect of the combination of FTRM #2 with other operating variables on the PFT is discussed in other sections, notably Sections 4.3.6, 4.4.6 and 4.2.6. These comparisons are shown in Figure 4.27 to show the complete picture of the effect of FTRM #2 on flame temperature.

4.6 Steady State (3 Hour) Tests

The steady state tests were run with the optimum test conditions found in the previous test sets. The optimum conditions were chosen based on SO_2 and NO_X emissions and operating efficiency. The conditions for the lowest SO_2 were found in test 26, the combination of FTRM #2 and 5% excess O_2. Under those conditions the SO_2 was reduced 31.4% at a Ca/S mole ratio of

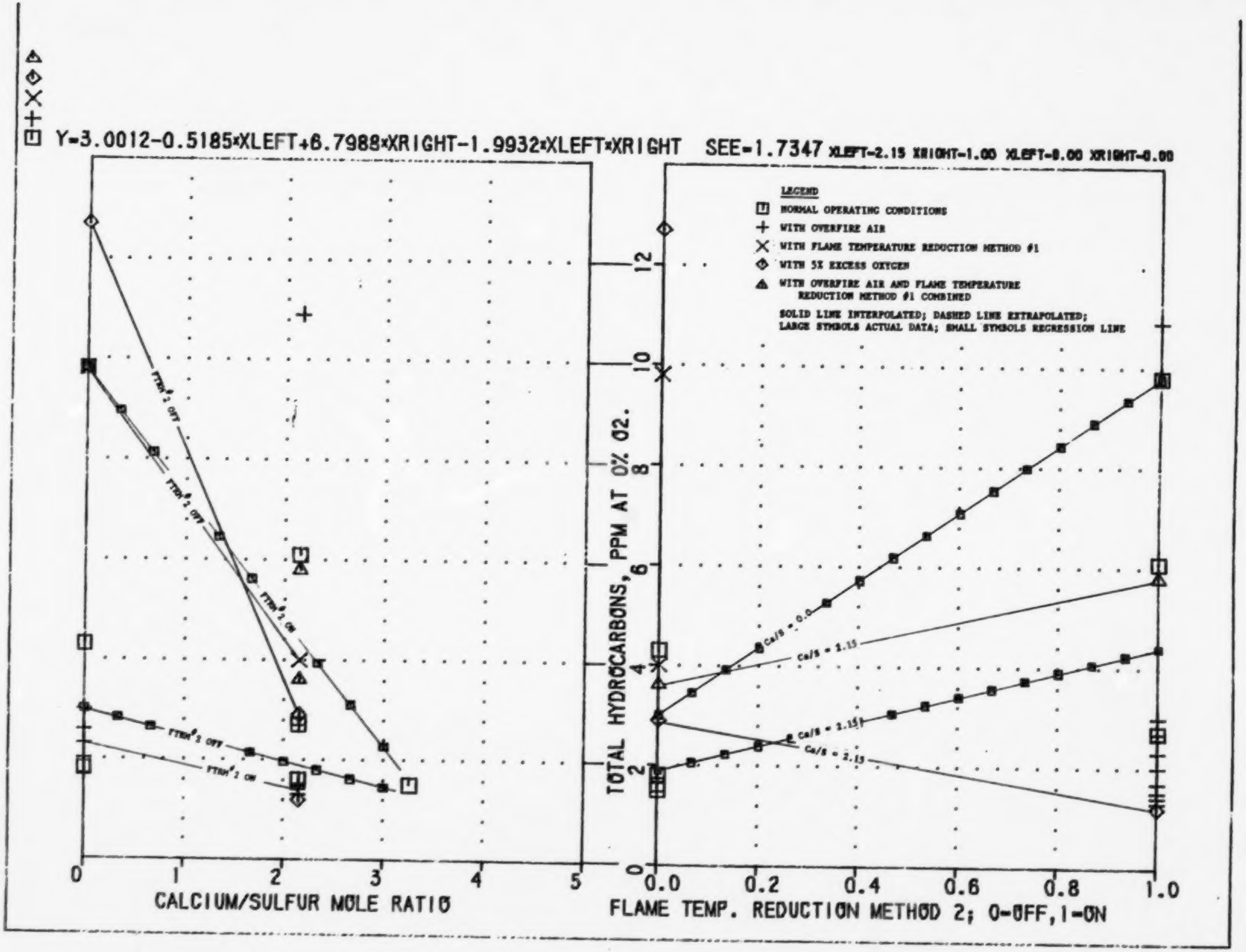

FIGURE 4.26: EFFECT OF FLAME TEMPERATURE METHOD #2 AND LIMESTONE ON TOTAL HYDROCARBONS

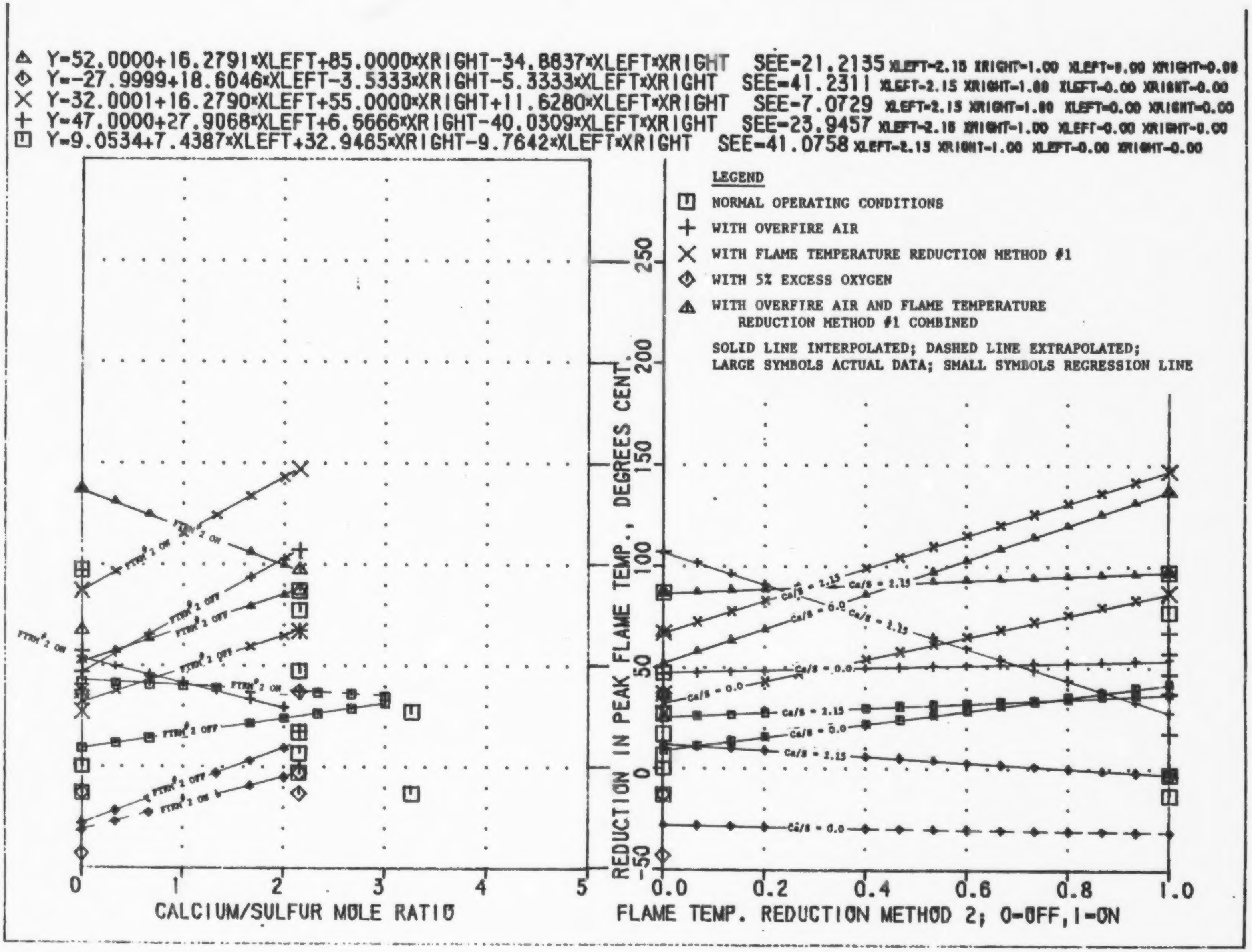

FIGURE 4.27: EFFECT OF FLAME TEMPERATURE REDUCTION METHOD #2 AND LIMESTONE ON PEAK FLAME TEMPERATURE

2.15 but the NO_x emissions increased from 0.32 lb/10^6Btu to 0.616 lb/10^6Btu. The greater SO_2 reduction is due to the use of 5% excess O_2 and FTRM #2 as shown by test 26 is almost completely counterbalanced by the increase in NO_x emissions. Additionally, the high excess O_2 would cause an efficiency penalty on boiler operation. The next best SO_2 reduction was achieved in test 23; the combination of FTRM #2 and OFA. In this test the SO_2 reduction was only 25.5% but the NO_x emissions were reduced to 0.19 lb/10^6Btu without an efficiency penalty, because of the use of OFA the CO emission would be expected to increase but it measured only 23 ppm. A comparison of the total acid forming species of these two tests with the test where no operating modifications were added, test 34, shows that test 23 is the optimum even without consideration of the energy penalty associated with high excess O_2.

Test No.	34	26	23
SO_2, lb/10^6Btu	3.97	3.42	3.71
NO_x, lb/10^6Btu	.309	.616	.192
Total, lb/10^6Btu	4.28	4.04	3.90

Hence test 23 was chosen for the steady state tests.

4.6.1 Analysis

Tests 42 and 43 were the steady state tests. The optimum settings found during the optimization series was with OFA and FTRM #2 combined; test 42 was run without limestone and test 43 was run with limestone addition at a Ca/S mole ratio of 2.15. The tests were run for about three hours each, with readings taken every half hour. The first reading was taken after 5 minutes of stable operation.

Some changes in temperatures and gas species were noted. During test 42 the secondary air temperature remained constant while in test 43 the secondary air temperature increased; if limestone was affecting the heat transfer in the air heater then the secondary air temperature would drop. The primary air temperature for both tests remained constant and the gas temperature of the air heater inlet and outlet remained constant. The rise in secondary air temperature during test 43 is attributed to fuel variation.

Only one gas species, the SO_3 concentration, changed remarkably during test 42. At the beginning of the test 8.1 ppm was recorded, after 40 minutes it rose to 13.9 ppm and after 1.5 hours it rose to 22.2 ppm. It remained at about 22 ppm for the remainder of the test. At the beginning of test 43 the SO_3 concentration dropped immediately to 7.9 ppm. It is possible that SO_3 was being absorbed by calcined lime remaining on the furnace surfaces (most probably in the convection sections) and that it took 1.5 hours for this lime to be flushed out of the system. This casts doubt on SO_3 measured during any test without limestone being added to the fuel, which was run after a test with limestone addition. This test sequence combination occurred on May 11. During the baseline test performed at the beginning of May 11, 29.5 ppm of SO_3 was recorded and during test 30 immediately after 28.2 ppm was recorded; test 30 had almost identical test conditions. It appears that the gradual increase in SO_3 concentration did not occur in tests performed at the beginning of May 11 as they did during test 42. Therefore, the actual reason for SO_3 increase seen during test 42 is unknown. It could have been a measurement error. Nevertheless, it would be worth further investigation during any future LIMB testing. The changes in NO_x and CO measured during the beginning of test 42 and 43 are attributed to the lower excess oxygen at the beginning of the tests.

The increase in SO_2 concentration at the end of tests 43 although quite large is attributed to fuel sulfur variability and not degradation of SO_2 capture.

4.6.2 SO_2/SO_3 Capture Across the Baghouse

It was anticipated that an additional 10% reduction in SO_2 would occur as the flue gases passed through the filter cake in the baghouse. No reduction in SO_2 or SO_3 was recorded. The results are presented in Table 4.2. Unexpectedly a very sharp drop in SO_3

concentration did occur between the air heater inlet and the airheater outlet. This drop in SO_3 concentration was measured for both test 42 and 43. The drop in temperature from 500°C (932°F) to about 190°C (374°F) is not low enough to cause condensation of SO_3 on boiler surfaces or ash particles. Predicted SO_3 dew point temperatures, based on empirical equations presented in Reference 3, at the air heater inlet are 181°C (359°F) and 143°C (289°F) for tests 42 and 43 respectively. Although the dew point for test 43 is low enough to cause some condensation on the coldest surfaces of the air heater a 98% reduction in SO_3 is too high to be the result of just condensation at or near the dew point. This effect should be investigated further.

The SO_2 measurements shown in Table 4.1 taken at the air heater inlet are slightly different from the measurements taken at the baghouse inlet and outlet. The reason for this difference is as follows:

The SO_2 concentrations measured at the inlet and outlet of the baghouse were obtained using an instrument different from that used for the measurements taken at the economizer outlet. Additionally all three measurements were taken sequentially, not taken simultaneously.

4.7 Mass Balance

A complete mass balance could not be made on the system because of the inability to accurately determine the furnace hopper ash quantity. This ash falls into a water trap at the bottom of the furnace and is continuously removed by a drag chain conveyor. The holdup time in the ash water sluice is on the order of 8 hours, hence any measurement from a three hour test would contain large errors because of ash holdup from previous tests.

TABLE 4.1. SO_2/SO_3 CAPTURE ACROSS BAGHOUSE

Concentration of Emission Species at Inlet and Outlet

	Corrected to 0% Excess Oxygen					As lb/10^6 Btu
Test No. 43						
Time	18:38	19:07	19:32	20:35	Avg.	
Air Heater Inlet						
NO_x, ppm	174	175	167	187	176	0.206
O_2,% *	2.9	3.0	3.4	3.0	3.1	
SO_2, ppm	2148	2189	2120	2277	2186	3.56
SO_3, ppm	7.9	7.7	8.5	9.0	8.3	0.017
Baghouse Inlet						
NO_x, ppm	159	167	158	188	167	0.195
O_2,%*	8.4	8.4	8.3	8.7	8.35	
SO_2, ppm	2174	2174	1990	1970	2060	3.35
SO_3, ppm	.3	.3	.3	.5	.3	0.0007
Baghouse Outlet						
NO_x, ppm	171	163	160	191	172	0.201
O_2,% *	8.7	8.7	8.5	9.1	8.75	
SO_2, ppm	2227	2227	2022	2037	2128	3.46
SO_3, ppm	0.3	0.3	0.3	0.5	0.3	0.0007
Difference (Baghouse Inlet-Outlet)						
NO_x, lb/10^6Btu						-.006
SO_2, lb/10^6Btu						-0.11
SO_3, lb/10^6Btu						0.0

*Excess oxygen level at which measurements were taken

TABLE 4.1. SO_2/SO_3 CAPTURE ACROSS BAGHOUSE (Cont'd.)

Concentration of Emission Species at Inlet and Outlet

	Corrected to 0% Excess Oxygen						As lb/10^6 Btu
Test No. 42							
Time	14:07	14:49	15:35	16:01	16:37	Avg.	
Air Heater Inlet							
NO_x, ppm	163	175	184	183	181	177	0.208
O_2,% *	2.9	3.0	3.3	3.2	3.0	3.1	
SO_2, ppm	3094	2948	2909	2952	2773	2939	4.78
SO_3, ppm	8.1	13.9	22.2	24.7	22.7	18.3	0.0373
Baghouse Inlet							
NO_x, ppm	150	166	175	181	176	169	0.198
O_2,% *	6.0	6.0	6.0	6.5	6.2	6.1	
SO_2, ppm	3016	3016	3080	2902	2843	2965	4.83
SO_3, ppm	.4	.7	.4	.6	.6	.6	.0011
Baghouse Outlet							
NO_x, ppm	147	171	177	187	175	171	0.20
O_2,% *	6.4	6.6	6.7	6.9	6.6	6.6	
SO_2, ppm	3099	3142	3238	2956	2850	3049	4.96
SO_3, ppm	.4	.6	.4	.4	.3	.4	0.0009
Difference (Baghouse Inlet-Outlet)							
NO_x, lb/10^6Btu							-0.002
SO_2, 1b/10^6Btu							-0.13
SO_3, lb/10^6Btu							0.0002

*Excess oxygen level at which measurements were taken

4.7.1 Particulate Loadings

Particulate loadings from test 42 and 43 were measured at the air heater inlet as follows:

Test No.	Fly Ash Loading at Air Heater Inlet	
	lb/10^6BTU	lb/hr
42	5.91	250.0
43	10.38	439.1

The flyash entering the furnace can be estimated by the product of the coal feed rate and the fraction of ash in the fuel. An average ash content of the fuel was used based on all the fuel analyses shown in Table A-1. For tests 42 and 43:

Test No.	Fuel Ash Fraction	Ash Entering Furnace lb/10^6BTU	lb/hr
42	0.097	7.62	322.0
43	0.194	15.24	644.7

The fraction of the entering flyash leaving the furnace is 78% and 68% for tests 42 and 43 respectively. The 78% compares well with field boilers where 20 to 25% of the flyash falls into the furnace hopper. For test 43, where limestone is added 32% retained in the furnace is higher than expected. It appears that, at the higher ash loadings, a greater fraction of the ash falls out in the furnace.

4.7.2 Limestone Addition Rate

Three composite fuel analyses were created to evaluate the amount of calcium entering the furnace. The first fuel analysis is an average of several analyses of coal and limestone sampled at the pulverizer outlet fuel samples 201, 202 and 204. The second analysis is made by adding the limestone composition to analyses 1, 105, 107, 110, 111, 113 and 114 A&B. The third composite is made by mixing in the lab 1500 parts of fuel sample 114B and 330 parts of limestone sample 311 and performing a laboratory fuel analysis on the mixture. All the composites were corrected to 2.5% H_2O to allow direct comparison and are shown in Table 4.2. The composites are all quite similar except for two inconsistancies, the oxygen content and the ash content. The oxygen inconsistancy is probably a result of the laboratory procedure, the oxygen content is not actually measured but is arrived at by difference; hence, it contains the cumulative errors of all six other procedures. The low ash content in composite 3 cannot be explained except that it might be the result of a fuel sample that was low in ash. The comparison of the three fuel analyses supports the measured limestone weight rate of 330 kg/hr.

TABLE 4.2. Composite Fuel Analyses

Composite	1	2	3
Ultimate Analysis, %			
C	61.05	59.94	58.53
H	3.93	3.91	4.13
O	9.05	11.37	15.78
N	1.1	1.08	1.15
S	2.53	2.86	2.41
H_2O	2.5	2.5	2.5
Ash	19.84	18.33	15.55

4.7.3 Sulfur, Calcium and Trace Balance

A detailed mass balance was performed for tests 42 and 43. The balance was performed on total ash, sulfur, calcium and the ash constituents SiO_2, Al_2O_3, Fe_2O_3 and MgO. The mass rate of each of these constituents was calculated from fuel and ash analyses of samples taken during the test. An ash analysis and weight rate for the furnace and economizer hopper were not available so they where calculated by difference. The ash rate of the furnace and economizer hopper were estimated by two methods: total ash difference and the sum of each constituent difference, these two methods should check if everything is correct. An assumption was made that the baghouse was 99.8% efficient and ash rates to the stack were calculated from this assumption. For the mass balance weight rates of the ash constituents SiO_3, Al_2O_3 and Fe_2O_3 were based on limestone analyses 303, 307, 309 and 315; analysis 311 had nil amounts of these constituents and thus was not included. The mass rate of the flyash to the baghouse was based on the particulate loadings measured at the economizer outlet.

The total mass balance for test 42 (Table 4.3) showed an ash rate of 8.68 kg/hr in the furnace and economizer hopper while the constituent balance showed a net ash loading of 32.28 kg/hr in the furnace and economizer hopper. Using these ash loadings a net carryover from the furnace and economizer of 92.92% and 73.66% respectively is calculated. One explanation for this difference in results is that the percentage ash in fuel sample 114A (8.17%) was unusually low compared to the average of 9.71% (standard deviation of 0.19) calculated without sample 114A: 8.17% is eight standard deviates from the average and is thus an outlier. Using the average ash content of 9.71% a recalculation results in a net carryover of 78% and 63% respectively. This latter calculation using the average fuel ash content is probably more reasonable.

The total mass balance for test 43 (Table 4.4) showed an ash rate in the furnace and economizer hopper of 132.38 kg/hr while the constituent ash rate was 171.14 kg/hr. Using these ash loadings the carryover from the furnace and economizer of 60.15% and 48.5% respectively is calculated.

The estimated sulfates in the furnace and economizer ash of 11.56% agrees with the percentage of sulfates measured in the flyash (9.36%). The utilization of calcium also agree at 12.78 and 13.85% respectively. Based on the sulfur estimated to be in the total ash the percent sulfur capture for test 43 is estimated to be 31.85%, slightly higher than the average of 28% for the test condition but it is typical of the maximum SO_2 capture measured during the test and not outside the range of expected values.

Closure is a comparison between the measured ourput of a process and the output of a process calculated based on the input; it is calculated as the ratio between the unaccounted for difference between the total ash and sum of the constituent ash loadings of the furnace and economizer hopper and the total ash input to the furnace. The results are as follows:

	% Closure	% Closure using average ash %
Test 42	19.25	15.03
Test 43	11.66	

These do not represent true closures because the furnace and economizer ash rate could not be measured or sampled due to the wet ash removal system. But an 11.66% closure is quite good considering the lack of information on the furnace and economizer ash.

TABLE 4.3. Mass Balance For Test #42, kg/hr

Stream No.		1 Coal Feed To Mill	2 Limestone Feed To Mill	3 Flyash To Bag-house	4 To Stack	5 Calculated Furnace & Economizer Hopper Ash by Difference	6 Calculated Composition of Ash, %
	Stream Weight	1500	0	113.64			
CALCIUM BALANCE							
Total Calcium		1.31	0	2.83	0.01	(-1.53)	
Actual Form	CaO	1.84		3.97	0.01	(-2.14)	nil
	$CaCO_3$	0					
SULFUR BALANCE							
Total Sulfur		41.10	0	0.75	44.00	(-2.15)	
Actual Form	SO_2	82.20			88.00		
	SO_3	0		1.86[7]		(-5.37)[7]	nil
TRACE BALANCE							
Total Ash[9]		122.55[8]	0	113.64	0.23	(8.68)[10]	
Actual Form	SiO_2	42.65	0	32.84	0.07	(9.65)	29.89%
	Al_2O_3	27.57	0	18.52	0.04	(9.01)	27.91%
	Fe_2O_3	42.77	0	29.09	0.06	(13.62)	42.19%
	MgO	0.37	0	0.41	0.00	(-0.04)	nil
	Other	7.35	0	26.95	0.05	(-19.65)	nil
						(32.28)[11]	100%

1. Uses fuel and ash analysis #114A.
2. No limestone was used for test 42.
3. Uses flyash analysis #42; total weight based on particulate loading.
4. Uses average of 5 SO_2 measurements 4.78 lb/10^6 Btu. and assumes 99.8% particulate control.
5. Estimated by difference.
6. % constituents in the furnace and economizer hopper ash (calculated).
7. Sulfates in ash not sulfur trioxide.
8. Fuel 114A had an unusually low ash percentage.
9. Includes any sulfates and calcium forms.
10. Ash in furnace and economizer hopper by difference using total ash flows.
11. Ash in furnace and economizer hopper by difference using constituent ash flows.

TABLE 4.4. Mass Balance For Test #43, kg/hr

Stream No.		1 Coal Feed To Mill	2 Limestone To Mill	3 Flyash To Baghouse	4 To Stack	5 Calculated Furnace & Economizer Hopper Ash by Difference	6 Calculated Composition of Ash, %
	Stream Weight	1500	330	199.59			
CALCIUM BALANCE							
Total Calcium		1.73	128.95	72.99	0.04	(58.65)	
Actual Form	CaO	2.92	0	102.20	0.06	(82.11)	47.97%
	$CaCO_3$	0	324.89	0	0	0	
SULFUR BALANCE							
Total Sulfur		48.30	0	7.47	32.92	(7.91)	
Actual Form	SO_2	0	0		65.81		
	SO_3	0	0	18.6[8]	0.04	(19.7)[8]	11.56%
TRACE BALANCE							
Total Ash[7]		142.65	189.72	199.59	0.40	(132.38)[9]	
Actual Form	SiO_2	46.22	0.48	23.35	0.10	(23.25)	13.58%
	Al_2O_3	29.10	0.03	15.47	.07	(13.59)	7.94%
	Fe_2O_3	56.63	0.07	25.55	0.11	(31.04)	18.14%
	MgO	0.43	1.98	1.04	0.00	(1.37)	0.80%
	Other	7.85	5.22	13.3	0.03	(-0.26)	nil
						(171.14)[10]	100%

1. Uses fuel and ash analysis #114B.
2. Uses limestone analysis #311 and average of 303, 307, 309 and 315 for SiO_2, Al_2O_3 and Fe_2O_3.
3. Uses analysis #43, total weight based on particulate loadings.
4. For SO_2 uses average of 4 reading 3.58 lb/10^6 Btu; assumes 99.8% particulate control.
5. All numbers are estimated by difference.
6. % constituents in the furnace and economizer hopper ash (calculated)
7. Includes any sulfates and calcium forms.
8. Sulfates in ash not sulfur trioxide.
9. Ash in furnace and economizer hopper by difference using total ash flows.
10. Ash in flurnace and economizer hopper by difference using constituent ash flows.

4.8 Limestone Fineness

Since the fineness of the limestone could not be measured separately from the fuel, a test was devised to ascertain qualitatively whether or not the limestone was pulverized finer than the coal. The test consisted of sieving the pulverized limestone and coal mixtures into four size ranges. The heating value of each size fuel was measured and compared with the heating value of sized pulverized coal that did not have limestone added. The size range that has the highest reduction in HHV contained the most limestone. The results Table 4.5 show that the highest reduction in HHV occurred in the size range finer than 200 mesh; this indicates that the limestone was pulverized finer than the coal. If the pulverizations were equal then the reduction in HHV would be the same for all size ranges.

TABLE 4.5: CHANGE IN HEATING VALUE OF SIZED PULVERIZED COAL AFTER ADDITION OF LIMESTONE AT A Ca/S MOLE RATIO OF 2.15

	% Reduction in HHV	
	Sample 506	Sample 507
Sieve Size		
50 mesh	---	---
50 - 100 mesh	1	2
100 - 200 mesh	16	13
- 200 mesh	21	18

4.9 Slagging Potential

Visual observation of the furnace during operation under normal conditions showed that slagging of the fuel did not occur both with and without limestone addition. Under operating conditions where overfire air is used, slagging did occur for tests both with and without limestone addition. This result is confirmed by measurements of ash fusion temperatures shown in

Table 4.6. These results show that the ash fusion temperatures are higher when limestone is being added at a Ca/S mole ratio of 2.15.

The problem of slagging, both with and without overfire air, can be alleviated on retrofit units through the use of Foster Wheeler's patented Boundary Air System. As shown in Figure 4.29. Boundary Air produces an oxidizing zone along the lower furnace walls and ash hopper.

TABLE 4.6: ASH FUSIBILITY TEMPERATURE

	Ash Fusion Temperatures			
	Test 42		Test 43	
Ca/S Mole Ratio	0		2.15	
Oxidizing Atmosphere				
	°C	°F	°C	°F
Deformation	1300	2372	1330	2426
Softening	1320	2408	1345	2453
Hemisphere	1375	2507	1380	2516
Flow	1405	2561	1485	2705
Reducing Atmosphere				
Deformation	1060	1940	1180	2156
Softening	1070	1958	1230	2246
Hemisphere	1080	1976	1285	2345
Flow	1345	2453	1400	2552

All ash fusion temperatures increase as the atmosphere changes from reducing to oxidizing; for instance the ash softening temperature increases by 450°F (250°C) without limestone addition, and by 207°F (115°C) with limestone. Also all ash fusion temperatures increase with the addition of limestone; the increase is largest under a reducing atmosphere. The reducing ash softening temperature increases 288°F (160°C) while the reducing hemisphere temperature increases by 369°F (205°C) when limestone is added to the fuel.

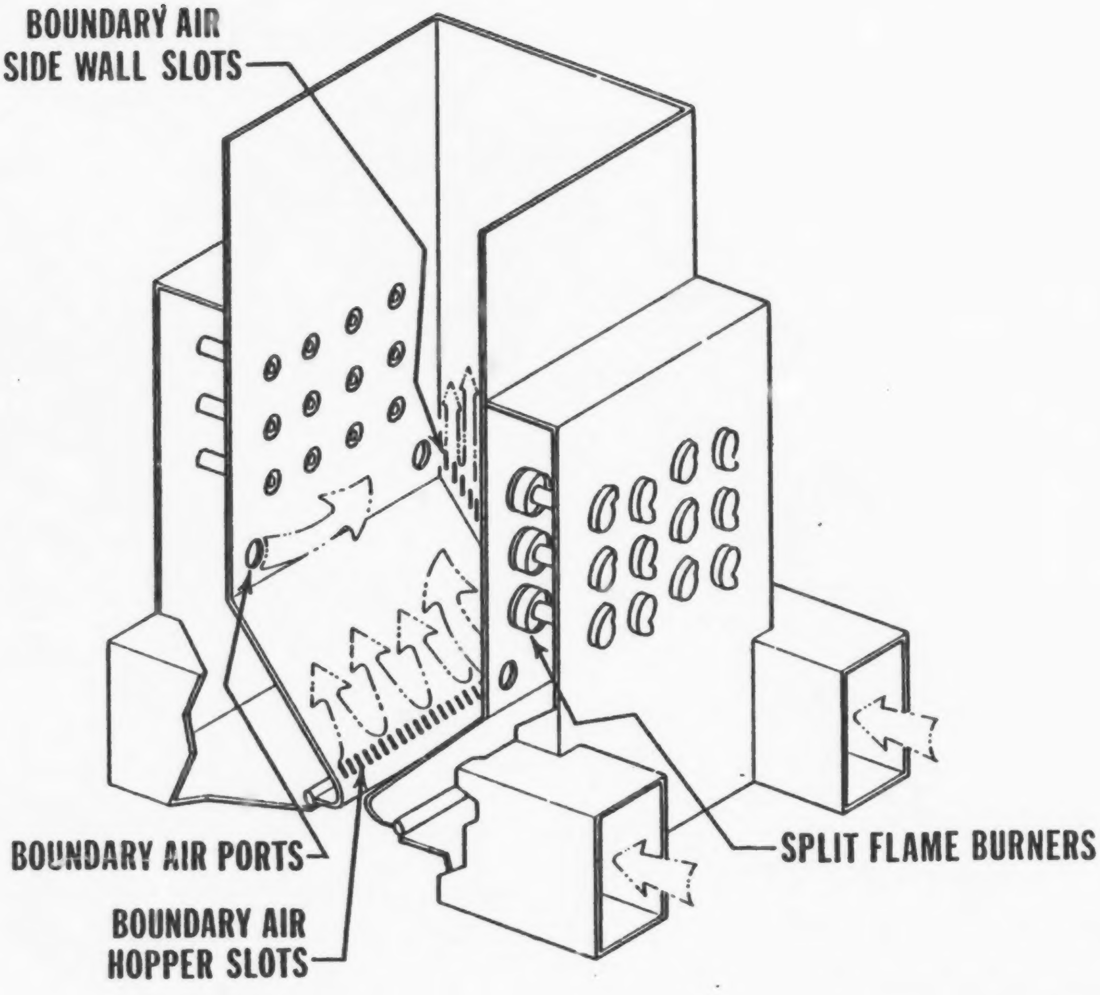
BOUNDARY AIR
SIDE WALL SLOTS
BOUNDARY AIR PORTS
BOUNDARY AIR
HOPPER SLOTS
SPLIT FLAME BURNERS

FIGURE 4.29: FOSTER WHEELER BOUNDARY AIR SYSTEM

4.10 Emission Reduction Using the Controlled Flow Burner

The Controlled Flow burner predecessor to the Controlled Flow/Split Flame burner was in place from previous work by IHI so the first day's testing was used to characterize this burner-fuel combination. After adjusting the registers and the movable tip for maximum NOx reduction the following results were obtained, typical results from the Controlled Flow Split/Flame Burner are shown for comparison:

Controlled Flow			Controlled Flow/Split Flame		
NOx lb/10^6 Btu	CO ppm*	O_2 %	NOx lb/10^6 Btu	CO ppm*	O_2 %
0.345	44	1.9	0.231	109	1.8
0.456	12	3.5	0.32	39	3.0
0.267**	36	3.5	0.234**	107	3.0

* CO concentration corrected to 0% excess O_2

** With 20% overfire air

Almost a 30% reduction in NOx was achieved at conventional CO and excess O_2 levels. Using 20% OFA reduced NO_x levels by 42% and 27% with the CF burner and CF/SF burner respectively. The CF burner with 20% OFA achieved NOx emissions only 17% lower than the CF/SF burner without OFA.

4.11 Comparison of Measured vs. Calculated Total Combustion Air

During the course of each test the primary and secondary air flow rates were measured, the results are tabulated in Appendix A Table 6. The some of the primary and secondary air flow rates is the total combustion air (TCA) flow into the furnace. The TCA can also be calculated from the fuel analyses in Appendix A Table 1. A comparison of these two methods of obtaining the TCA is shown in Figure 4.30. The predicted TCA of each regression equation agrees within 1% of each other; this is excellent

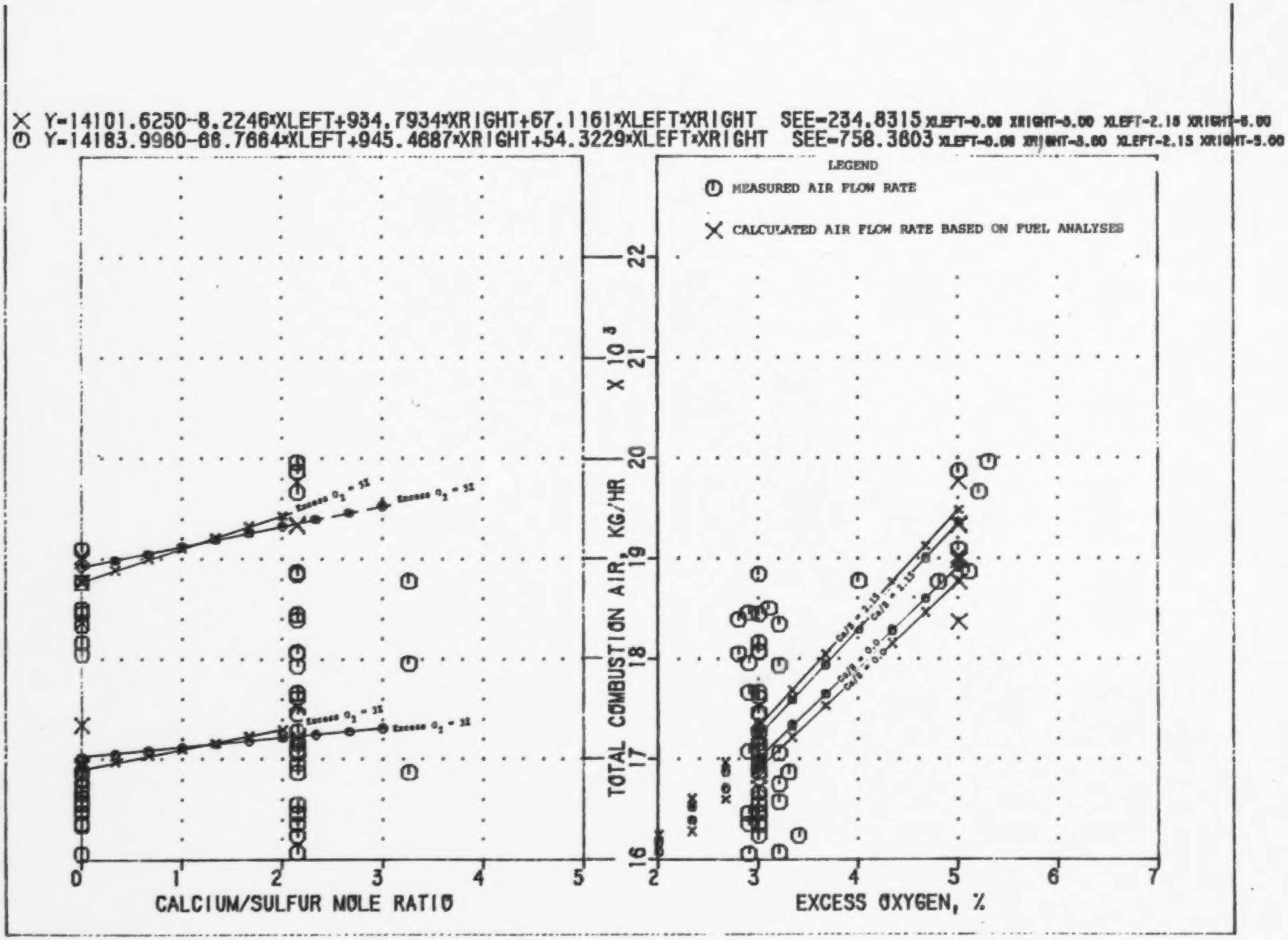

FIGURE 4.30: COMPARISON OF MEASURED AND CALCULATED TOTAL COMBUSTION AIR

agreement. The major difference between the two is the larger variabilities of the measured TCA is almost three times that of the calculated TCA.

The calculated TCA was based on fuel analysis all corrected to 2.5% moisture because that was the typical moisture of fuels sampled as the pulverized fuel storage bin. This was the only correction made during the calculation of TCA. The TCA was calculated using FW's combustion Analysis Computer Program.

5.0 COMPARISON OF RESULTS WITH PREVIOUS TESTS AT THIS LABORATORY

Previously IHI has tested FWEC's CF/SF burner with other coals. Table 5.1 compares the Kittaning coal with the Japanese Horonai coal. The Horonai and Kittaning coal are both classified by ASTM D 383 as high volatile A bituminous coals and are similar except for the different ratios of fixed carbon to volatile matter and the obvious ash and sulfur content.

5.1 NO_x Emissions of Previous Test Series

The NO_x emission rate from each coal should be different due to the differences in coal properties. Figure 5.1 shows the NO_x and CO concentrations of the two coals. The Kittaning coal proved to have the higher NO_x emission rate at the same excess O_2. The Horonai coal NO_x level is lower even though it had the highest fuel nitrogen content. The higher fixed carbon (FC) to volatile mater (VM) ratio (FC/VM = 1.45 for Kittaning vs 1.0 for Hononai) is responsible for the higher NO_x emission rate without OFA. When OFA was added the Kittaning fuel had a reduction in NO_x of 25%. The Horonai fuel with a much lower initial NOx level, did not show any reduction in NO_x with OFA. The CO characteristic for each fuel fell into a very narrow band, as the excess O_2 was reduced the CO concentration would increase rapidly below a certain O_2 level. The pattern of response of the NO_x and CO emission rates to excess O_2 and OFA are similar enough to justify the claim that the burner and furnace were operating in a similar manner for the fuels.

NOTE: Data shown in Figure 5.1 with tick marks were taken during the burner optimization series before the limestone optimization series. Each of these data points were taken during an interval about 5 minutes in length and are added as adjunct data points, they do not represent complete tests.

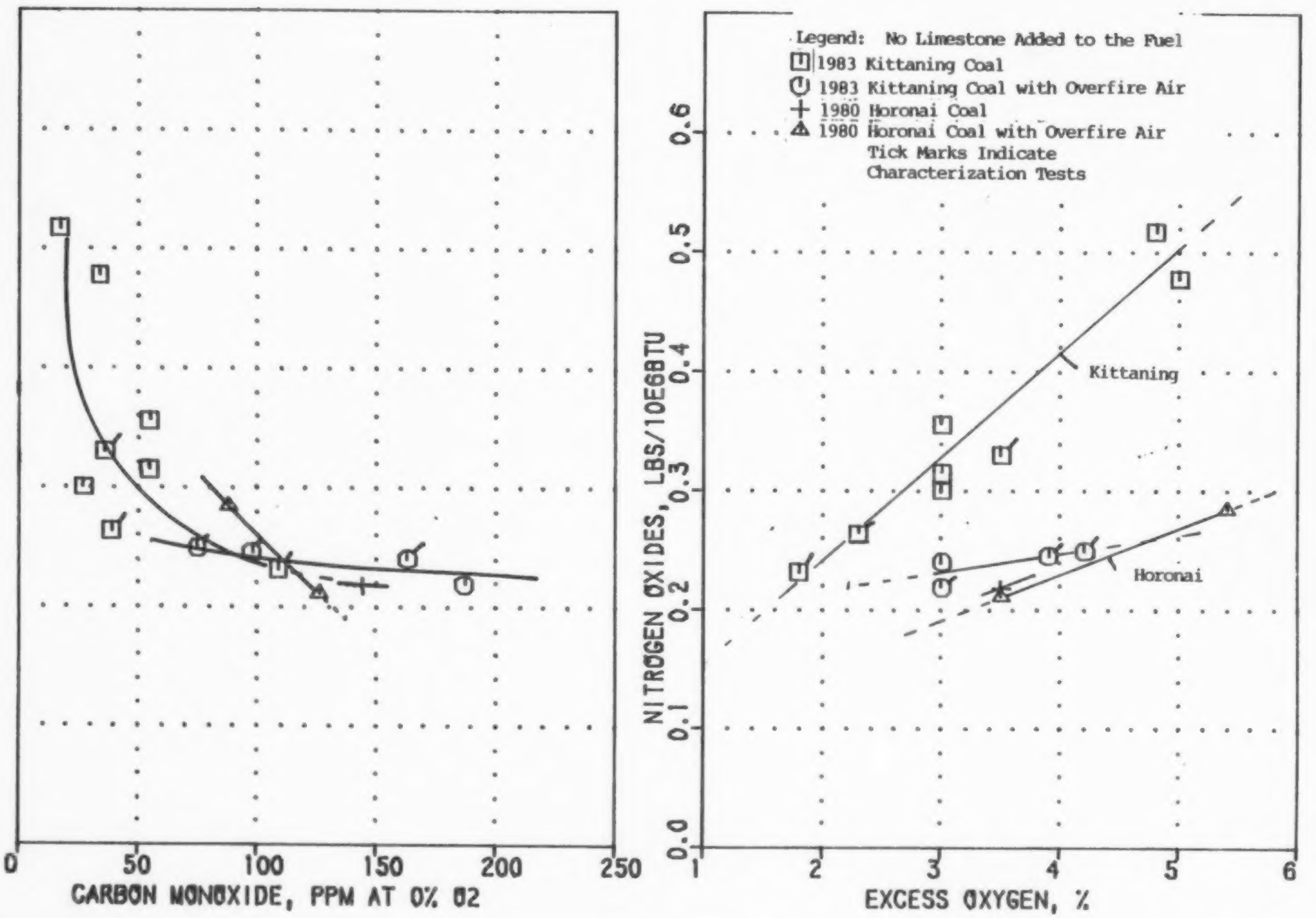

FIGURE 5.1: COMPARISON OF NOx AND CO EMISSIONS DURING 2 DIFFERENT TEST SERIES

TABLE 5.1: FUEL COMPARISON: JAPANESE AND U.S. COALS

Test Series Fuel Name Origin	1980 Horonai Japan	1983 Middle Kittaning Western PA
Proximate		
Fixed Carbon, %	38.4	50
Volatiles, %	39.7	34.6
Ash, %	20.1	9.5
Moisture, %	1.85	5.8
Ultimate		
Carbon, %	65.5	68.7
Hydrogen, %	5.23	4.6
Oxygen, %	5.65	7.1
Nitrogen, %	1.45	1.2
Sulfur, %	0.22	3.1
HHV, Btu/lb	11,421	12,818
Operating Conditions		
Fuel Rate Kg/hr	1,711	1,500
Heat Input 10^6 Btu/hr	42.99	42.3

5.2 Comparison of Flame Temperature Reduction Achieved During the 1983 Tests and 1980 Test Series.

During the 1980 test series with the Horonai coal the two flame temperature reduction methods were tested for their ability to reduce flame temperature and their effect on flame shape and burner performance. These two methods were used during the 1983 test series as an attempt to improve the SO_2 capture potential of LIMB. A comparison of the peak flame temperature reductions during each test series is shown in Figure 5.2. In general the flame temperature measured at all nine locations decreases but the peak flame temperature is the most sensitive to reduction methods. The peak flame temperature has the largest impact on dead burning of the limestone since the stone reaction rate increases exponentially with temperature. A small reduction in the peak flame temperature can have a large impact on dead burning of the limestone.

The reduction in peak flame temperature (PFT) by FTRM 1 and 2 showed reasonably consistent results between the 1980 and 1983 test series. Table 5.2 shows selected tests from both series. The tests were selected for both years on the basis of identical operating conditions. The major difference between the two test series is that during the 1980 tests the excess oxygen was 3.5% while for those at 1983 the excess oxygen was 3.0%. Additionally the absolute flame temperatures in 1983 were higher by an average of 127°C (228°F) under normal operating conditions.

The use of FTRM #2 reduced PFT typically by 40°C (72F) and 27°C (49°F) for 1980 and 1983 respectively. The use of FTRM #1 reduced PFT typically by 50°C (90°F) and 37°C (67°F) for 1980 and 1983 respectively. The use of both methods combined reduced PFT typically by 120°C (216°F) and 87°C (157°F) for 1980 and 1983 respectively.

TABLE 5.2: COMPARISON OF FLAME TEMPERATURE REDUCTION EFFECTIVENESS IN THE 1980 AND 1983 TEST SERIES

	Reduction in Peak Flame Temperature, °C (°F)			
	1980		1983	
FTRM #1	50	(90)	37	(67)
FTRM #2	40	(72)	27	(49)
1 & 2 Combined	120	(216)	87	(157)

6.0 TEST FACILITY DESCRIPTION

IHI's test facility is designed to evaluate fuels and combustion systems on a prototype scale (up to 50 x 10^6 Btu/hr). Functionally useful steam is not generated so that operation and design changes do not affect the steam supply to industrial or power generation equipment. This provides an atmosphere conducive to testing without interruption.

A flow diagram of the test facility is shown in Figure 6.1. The pulverized coal system differs from that which is in current commercial practice on pulverized coal-fired boilers. An indirect storage system is used and allows wide variations in air/coal ratios to be obtained. The limestone bunker supplies, via a feeder, a Foster Wheeler vertical MBF pulverizer. The coal and limestone are mixed and pulverized in the mill to a minimum coal fineness of 70% through 200 Mesh. The pulverized fuel is carried pneumatically to a cyclone separator where the fuel is separated from the carrier air and fed into a pulverized fuel bin; a baghouse filters the air before exhausting to the atmosphere, and collects the fines which are also fed into the fuel bin. A screw feeder at the bottom of the fuel bin feeds the pulverized fuel over a weighing device and into a fuel-primary air mixer. This allows great flexibility in controlling the primary air to fuel ratio.

The facility is fired by a single burner which simplifies burner flame studies since flame interactions do not occur. Nine view ports are installed along each side of the furnace at the burner level, along with five others at upper elevations. This allows the operator to observe the flame and take temperature measurements at different points along the flame's length. Overfire air ports are available for staging tests.

The combustion air takes the following path through the system. A forced draft fan supplies atmospheric air to the shell side of a tubular air preheater where it is heated up to the range of 280 to 345°C (536 to 653°F). Hot air is mixed with cold tempering air to obtain the desired primary air temperature. The remaining hot air is then supplied to the windbox. Combustion products pass out of the furnace, through a convection section and through the tube side of the preheater after which it is cleaned of particulate matter in a multiclone and then a baghouse. After the baghouse, an induced draft fan forces the combustion products to the stack.

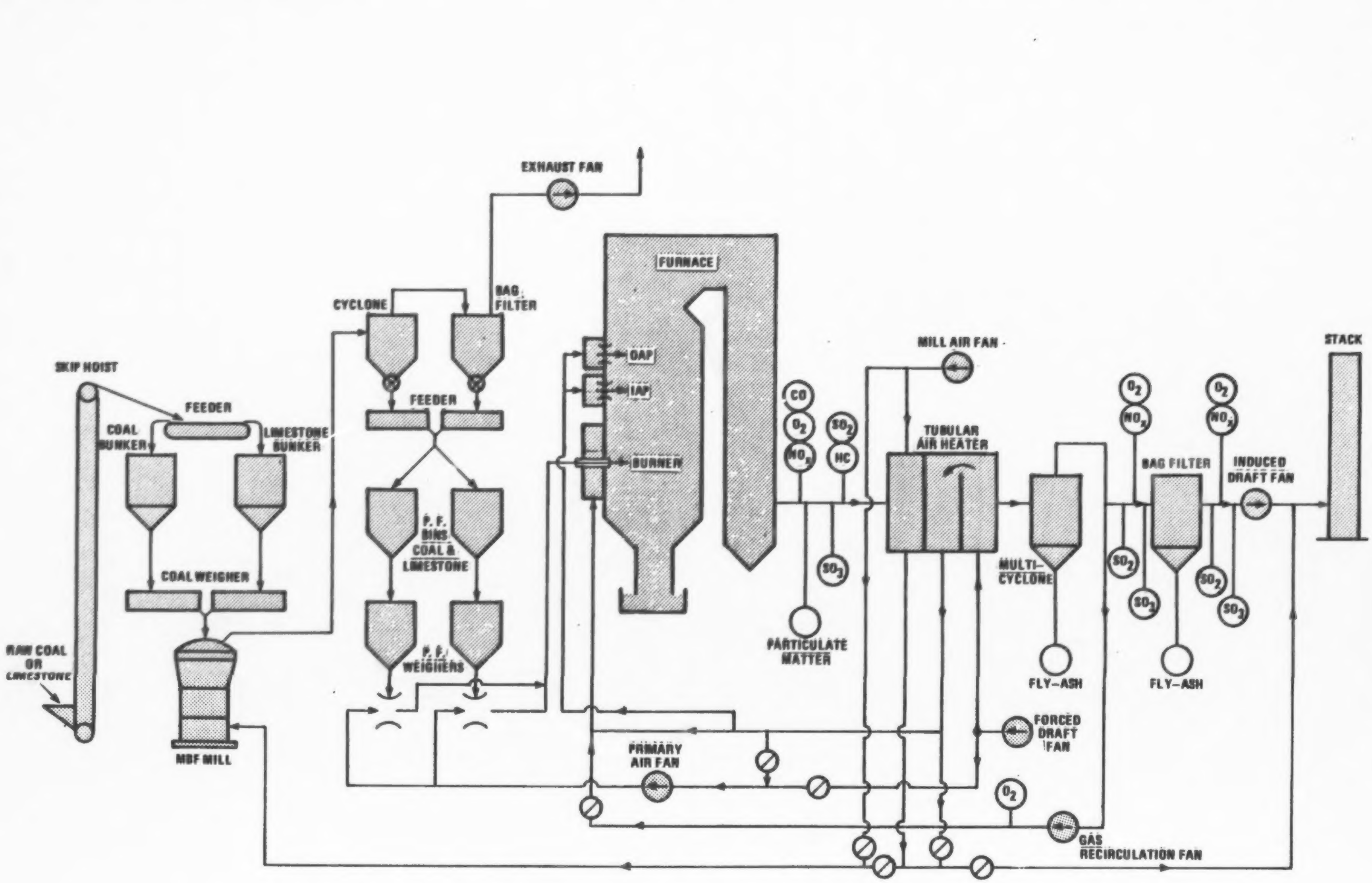
SKIP HOIST
RAW COAL OR LIMESTONE
FEEDER
COAL BUNKER
LIMESTONE BUNKER
COAL WEIGHER
MBF MILL
CYCLONE
BAG FILTER
EXHAUST FAN
FEEDER
P. F. BINS COAL & LIMESTONE
P. F. WEIGHERS
FURNACE
OAP
IAP
BURNER
PRIMARY AIR FAN
CO
O2
NOx
SO2
HC
SO3
PARTICULATE MATTER
MILL AIR FAN
TUBULAR AIR HEATER
FORCED DRAFT FAN
O2
MULTI-CYCLONE
FLY-ASH
GAS RECIRCULATION FAN
O2
NOx
SO2
SO3
BAG FILTER
FLY-ASH
O2
NOx
SO2
SO3
INDUCED DRAFT FAN
STACK

FIGURE 6.1: SCHEMATIC FLOW DIAGRAM OF TEST FACILITY AT AIOI

Table 6.1 Summarizes basic system parameters:

TABLE 6.1

SYSTEM SPECIFICATIONS

Furnace	Width:	3100 mm (10.2 ft)
	Depth:	4500 mm (14.8 ft)
	Height:	11,000 mm (36 ft)
Burner	Coal:	200 kg/h (4,400 lb/h)
	Overfire Air:	As Necessary
	Heat Liberation:	Max. 111 x 10^6 Kcal/m^3h (12.5 x 10^3 Btu/ft^3h)
Coal Handling	Elevator	1. 5 T/H (11 x 10^3 lb/h)
	Bunker:	1. 10 m^3
	Table Feeder:	2. 15 T/H (33 x 10^3 lb/h) max.
Pulverizer	Type:	IHI-FW Ring & Roller Mill MBF-16
	Capacity:	8 T/H (17 x 10^3 lb/h)
	Fineness:	70% through 200 mesh
Tubular Air Preheater	Air Flow Rate:	31 T/H (68 x 10^3 lb/h)
	Air Temp. Inlet:	20°C (70°F)
	Air Temp. Outlet:	320°C (610°F)
Particulate Collection Equipment	Type:	Baghouse following a multiclone
	Gas Flow Rate:	20,000 Nm^3/min (12440 scfm)
	Dust Loading	
	Inlet:	36, g/Nm^3 (87 gr/scf)
	Outlet:	0.1, g/Nm^3 (0.242 gr/scf)
Limestone Handling	Bunker:	225 Kg/h (500 lb/h) Max.
	Feeder:	20-320 Kg/h (50-700 lb/h)

6.1 Description of Controlled Flow/Split-Flame Burner

The most direct method for controlling NO_x is by some form of staged combustion. It is well known that the cooler, staged combusiton reduces thermal NO_x, while substoichiometric conditions reduce fuel NO_x. The method formerly used to control burner stoichiometry involved firing the coal with substoichiometric air quantities and completeing combustion with staging ports introducing the remaining air into the combustion process.

FWEC has developed two low NO_x burners which achieve large reductions in NO_x without burner staging. The first generation design is the Controlled Flow burner (Figure 6.2 insert) which is a dual register type capable of achieving 40-50% lower NO_x levels than were emitted by pre-NSPS turbulent burners. The second generation Controlled Flow/Split-Flame (Figure 6.2) burner produces NO_x levels over 60% lower than pre-NSPS designs. The Controlled Flow and Controlled Flow/Split-Flame are similar, the coal nozzle being the major difference. It is the latter design which was used for this program, the following functional description outlines both burners' relevant features:

Secondary Air Control - A series-register arrangement, common to both designs, allows simple burner controls to be used. The inner register, which regulates the degree of swirl around the coal nozzle, is controlled by a manual drive since continuous adjustment is not required. At the test facility the outer regiser was controlled by a manuel drive; in a commercial installation the outer register is controlled by a standard electric drive for operation as "closed", "ignite", and "operate" positions. The register arrangement divides the secondary air into two concentric streams which independently vary swirl. The secondary air flows axially into the furnace with almost no component directed radially inward, toward the burner centerline. Two registers permit the mixing rate between the primary and secondary air streams and the rate of entrainment of furnace gases, to be controlled.

Split-Flame Coal Nozzle - Coal is injected into the furnace through an annular nozzle which has been modified to separate the coal into concentrated streams, each of which forms an individual flame. Four streams are indicated in Figure 6.2 but the number is a design variable.

CONTROLLED FLOW/SPLIT FLAME LOW NO$_X$ BURNER

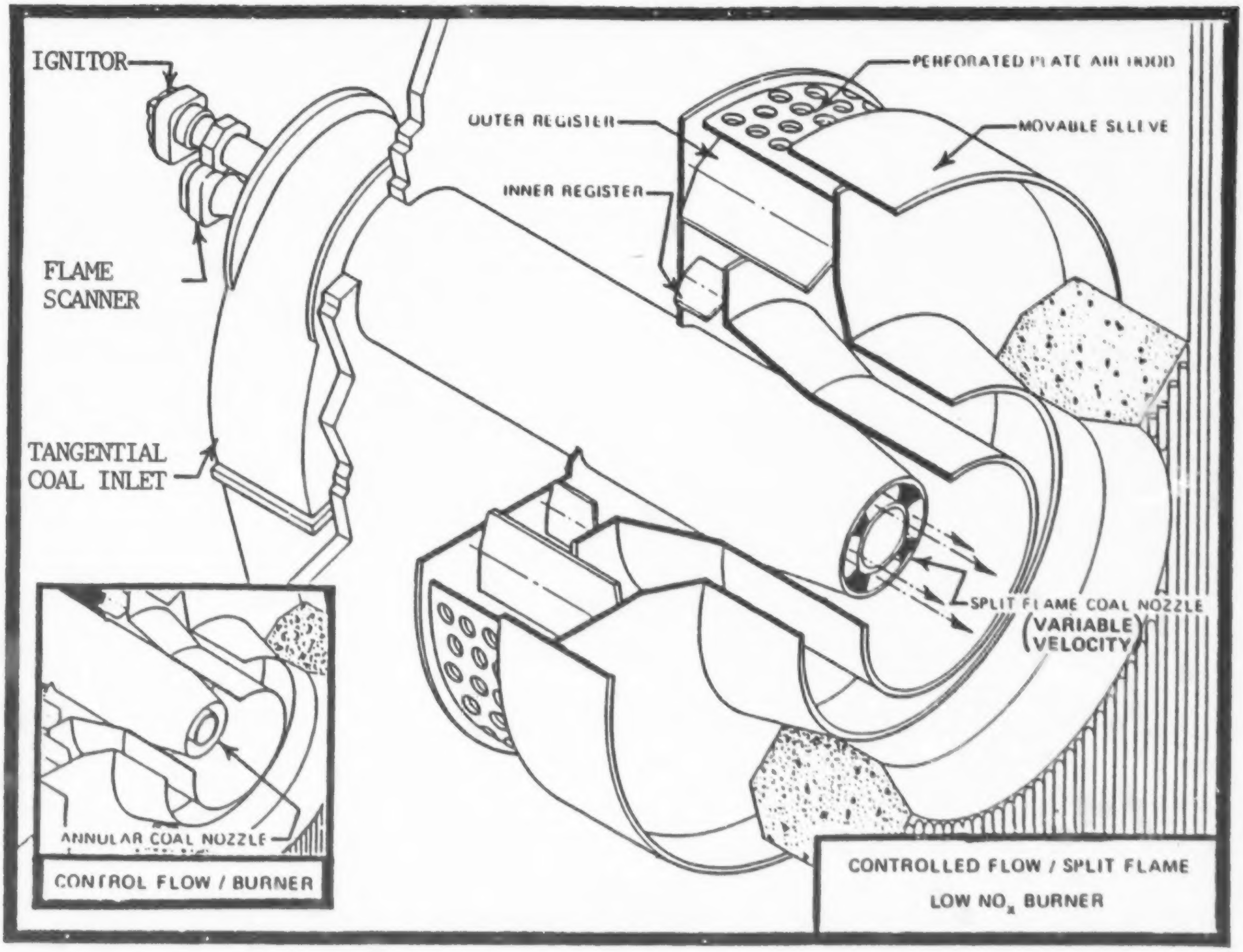
IGNITOR
PERFORATED PLATE AIR HOOD
OUTER REGISTER
MOVABLE SLEEVE
INNER REGISTER
FLAME SCANNER
TANGENTIAL COAL INLET
SPLIT FLAME COAL NOZZLE
(VARIABLE VELOCITY)
ANNULAR COAL NOZZLE
CONTROL FLOW / BURNER
CONTROLLED FLOW / SPLIT FLAME LOW NO$_x$ BURNER

FIGURE 6.2: CONTROLLED FLOW/SPLIT FLAME LOW NOx BURNER

The split-flame nozzle minimizes mixing between the coal and the primary air. The combination of the concentrated coal streams and the staged secondary air produces near throat flame stoichiometries in the 60 to 70 percent range up to about two throat diameters into the furnace. At that point, the swirling secondary stream from the outer annulus containing the remainder of the combustion air combines the flames and provides sufficient mixing to ensure adequate carbon burnout. Uniform distribution of coal about the periphery of the annular passageway is attained, as with pre-NSPS burners, by use of the tangential coal inlet. There is no undesirable roping of the coal. The inner sleeve tip is axially movable thereby providing a means for varying the primary air velocity while primary air flow is maintained constant. This velocity adjustment is used to optimize the primary air/secondary air velocity ratio which minimizes shear-induced turbulence.

The basic Controlled Flow burner employs a tapered annular nozzle instead of a split-flame nozzle. The Controlled Flow burner also has a movable inner sleeve tip for varying the primary air velocity.

The flows from both the Controlled Flow and the Controlled Flow/Split-Flame burners are axial and symmetrical about the burner axis. The only flow-induced turbulence is that which is deliberately provided by register swirl setting. This produces early staging of the flames with a minimum of unintentional mixing between the fuel particles and the combustion air.

6.2 Low NO_x Burner Background

Foster Wheeler has developed a low NO_x burner that is commercially installed and operating in numerous industrial and utility steam generators and has been standard equipment on boilers sold since 1979. This burner has demonstrated that large reductions in stack NO_x concentrations are obtainable strictly by modification of the combustion process. It has achieved this result over a wide range of boilers from 100,000 lb steam/hr to a 660MW utility boiler.

6.2.1 Evolution of Low NO$_x$ Coal Burners

In 1971 the United States Environmental Protection Agency established the New Source Performance Standards (NSPS) which initially limited NO$_x$ to .7 lb/10^6 Btu input for new coal fired central station steam generators. This regulation could be met with the high turbulence pre-NSPS burner design by enlarging the combustion zone to reduce flame temperature and reducing the burner stoichiometry with air ports to stage the combustion. FW used this technique on industrial and utility boilers until 1976, after which low NO$_x$ burners were offered. High turbulence burners were designed to burn coal with a hot flame to minimize unburned combustible loss. Unfortunately, this approach also produces high NO$_x$ le[illegible].

A high [illegible]nt burner design was originally installed on Public Service of New Mexico's San Juan Unit 1 with over fire air ports to control NO$_x$. This method reduced NO$_x$ 30 to 35% by reducing burner stoichiometry to no less than 96%. While this was adequate to meet the federal EPA standard, a 60% reduction was necessary to meet the State of New Mexico's limit of .45 lb/10^6 Btu. This large reduction would have required lowering burner stoichiometry to about 75%. Such a strongly reducing atmosphere in the lower furnace could increase slagging and tube wastage, as well as increasing unburned carbon, CO and hydrocarbons. The unit was, instead, retrofitted with the Controlled Flow, Split Flame (CF/SF) burner, which meets the New Mexico regulation without using air ports. Figures 6.2 and 6.3 respectively, show the burner configuration and the test results for San Juan Unit 1.

The predecessor to the CF/SF burner was the Controlled Flow (CF) burner. It was similar in design, except it lacked the splitter provisions in its movable nozzle. It was developed on a four-burner industrial unit, producing a 40% reduction from the originally

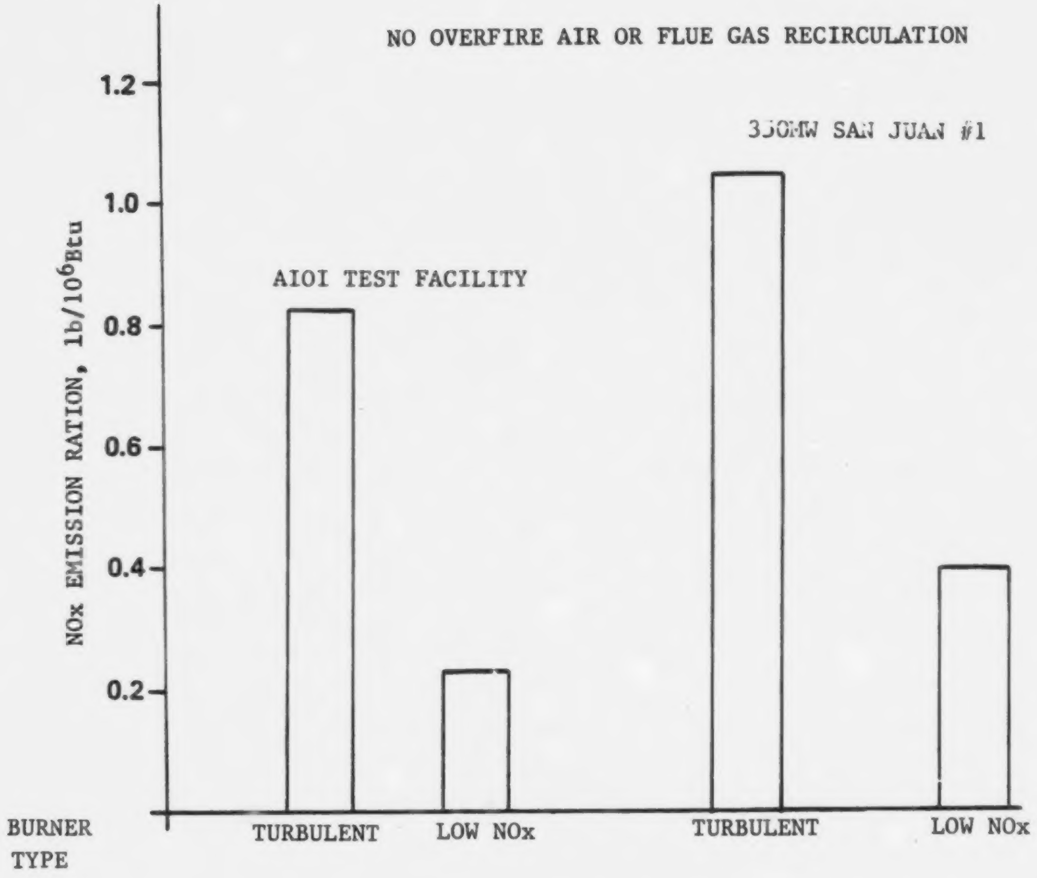

FIGURE 6.3 LOW NOx BURNER EFFECTIVENESS ON SCALE UP: SAN JUAN TESTS RESULTS

installed high turbulence burners. Later, the split flame coal nozzle was added and tested on this same unit, yielding a reduction of 60% to 70%. Figure 6.4 summarizes these developmental test results.

6.3 Problems During Testing

1. On April 19 a fan bearing failed. Replacement of the fan bearing was accomplished on April 24 and testing restarted on April 25. The bearing failure was found at the beginning of the test day no test fuel was used.

2. On April 27 a water leak into the furnace was detected. The leak was on top of the nose and water was seen running down the nose and dripping into the furnace. The leak was discovered at the beginning of the day so no test fuel was used. The plant operator was quite convinced that the leak was not present the night before after shutdown. The leak was repaired that day and testing continued the following day.

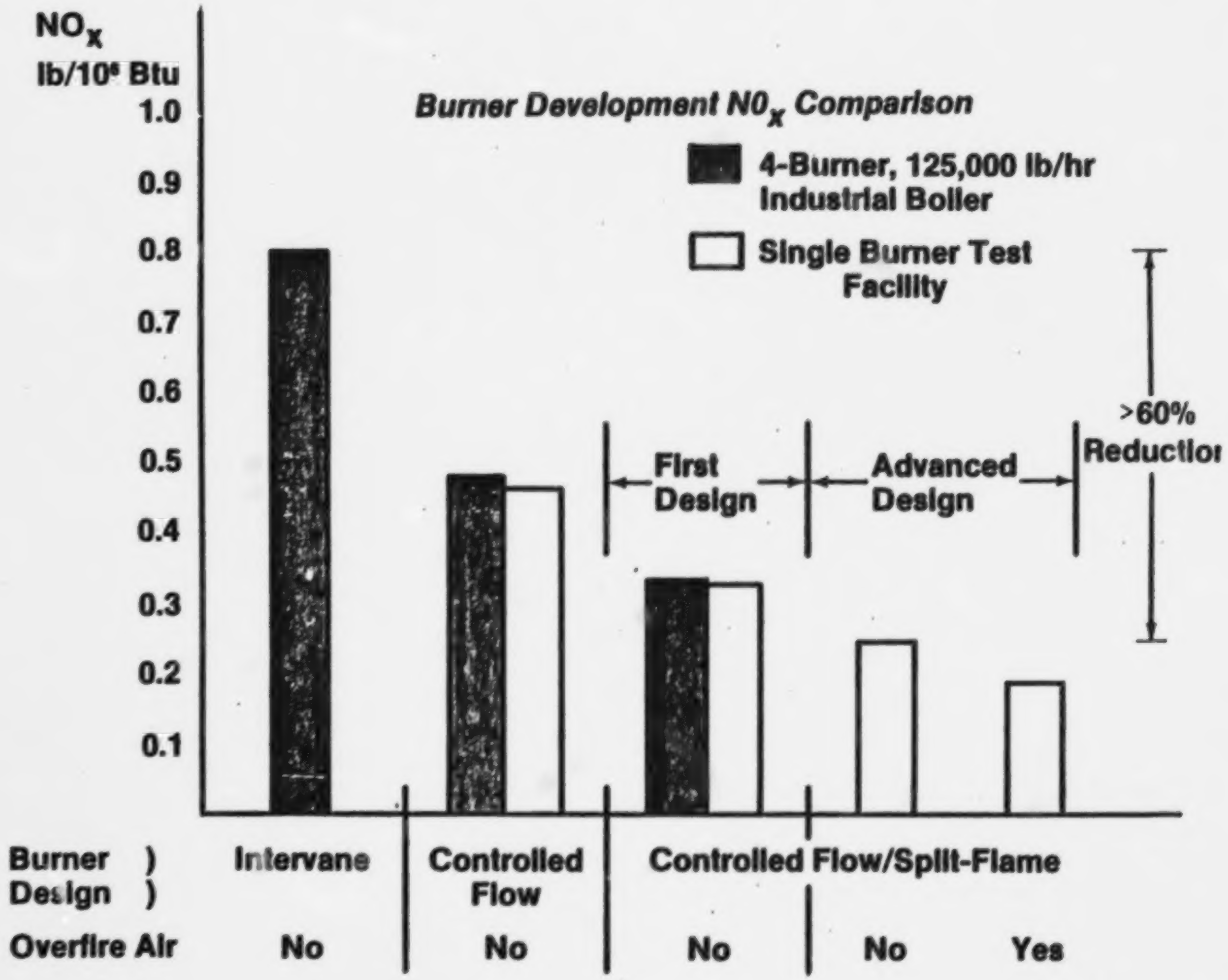

FIGURE 6.4: BURNER DEVELOPMENT NOx COMPARISON

7.0 LABORATORY EQUIPMENT, QUALITY ASSURANCE AND MEASUREMENT METHODS

This section describes the laboratory equipment used during the test program, the associated measurement methods and the results of the Quality Assurance Plan (Appendix C). Deviations from the methods and equipment described in the Quality Assurance Plan are discussed as well as results of Quality Assurance tests of precision and accuracy of the analytical procedures. Additional Quality Assurance results are described in other portions of this report:

- Section 4.0 gives an in-depth discussion of the agreement between sulfur in the coal as sampled and the SO_2 measured in the flue gas during tests without limestone addition. The two methods are in agreement within 2.2%; this is excellent agreement.

- During steady state tests, reported in Section 4.6, measurement of SO_2 and O_2 at different locations using different instruments is reported. The coefficient of variations for the three measurement each for tests 42 and 43, after correction to the same excess O_2, are 3.04% and 1.91% respectively.

- Section 4.7.2 discusses the accuracy of the limestone to coal feed rate by comparing an actual fuel anlaysis of the limestone coal mixture with a mathematical composite and a laboratory composite fuel analysis.

- Section 4.11 compares the measured vs. calcualted total combustion air. This comparison shows that good agreement was found between the air flow measuring device, the coal and limestone measuring device and the analytical methods used in the lab. It also shows that the fuel analysis method had much larger variability in results; this variability can be attributed to the fact that a fuel analysis measures only a small sample on a non-homogeneous material.

- o Section 5.0 compares the present test results with previous tests showing similitude of operation of many aspects of the present test program.

Standard sampling calibration and analysis methods were used in all possible cases. The exceptions are measurement of SO_3, coal and limestone weight rate, barometric pressure and measurement of the burner register opening. Table 7.1 shows the Japanese standard methods and the U.S. equivalent standard methods.

The method used at AIOI is the spiral tube condensation method--sodium borate titration. This is equivalent to the Goksoyr/Ross method for determining SO_3. The Goksoyr/Ross method is published in the APCA Journal[4] under support from the U.S. Environmental Protection Agency. The only difference noted beween the published method and the method used in Japan is the use of sodium borate for titrating the G/R coil rinse instead of sodium hydroxide listed in the published method. Sodium borate is less caustic and therefore safer to handle in a field situation; additionally, sodium borate is stable while sodium hydroxide must be prepared fresh daily and protected from the neutralizing effect of CO_2 in the air.

Coal and limestone weight rates were measured by loss in weight feeders. This type of feeder uses electric cells to weigh a chamber that is emptied continuously so that the loss in weight of the chamber is maintained at the set point. As the chamber empties it trips a fill switch and the chamber is refilled, during this refill period the output of the weigh cells is ignored and the coal or limestone rate is maintained at a constant speed. At the end of the refill period the emptying rate is corrected to match the set point.

Barometric pressure was measured by a mercury barometer.

The burner registers were always adjusted to minimize mechanical backlash. When changing the register setting the operator always sets the indication position in the direction of increasing the register setting. That is in order to eliminate backlash error when going to a lower register setting, the register is opened 20 degrees beyond the desired setting and then returned to the intended setting. When increasing the register setting the indicator is adjusted until the indicated setting is achieved.

TABLE 7.1 STANDARD METHODS

Measurement Parameter	Sampling	Calibration	Analysis
Combustion Air Flow	PTC 19.5[1] Chapter 4 JIS Z 8762[7]	Fluid Meters[2] JIS Z 8762	PTC 19.5 Chapter 4 JIS Z 8762
Ambient Conditions			
Temperature (ID Fan Inlet)	PTC 19.3 Part 3 Chapter 3 JIS Z 8705	PTC 19.3 Part 3 JIS Z 8705	PTC 19.3 Part 3 JIS Z 8705
Relative Humidity	E 337[3] JIS Z 8806	E 337 JIS Z 8806	E 337 JIS Z 8806
Barometric Pressure	D 3631[3] NP[8]	D 3631 NP	D 3631 NP
Flame Temperature	PTC 19.3 Part 3 JIS Z 8706	PTC 19.3 Part 3 JIS Z 8706	PTC 19.3 Part 3 JIS Z 8706
Coal and Limestone Fineness	D 197 JIS M 8811	D 197 JIS M 8811	D 197 JIS M 8801 JIS Z 8801
Combustion Air & Gas Temperature	PTC 19.3 Part 3 Chapter 3 JIS 8704	PTC 19.3 JIS Z 8704	PTC 19.3 JIS Z 8704
Coal Analysis Ultimate, Proximate and HHV	D 2234 JIS M 8811	D 3172-79 D 3286 JIS M 8811	D 3172-79[6] D 3286 JIS M 8812,13,14
Limestone and Ash Analysis	D 2234 JIS M 8811	D 3682 JIS M 8815	D3682 JIS M 8815
Coal and Limestone Rate	PTC 19.5 Chapter 1 NP	PTC 19.5 Chapter 1 NP	PTC 19.5 Chapter 1 NP
Five Gas Species	PTC 19.10 Part 10 & Method 19[4,5]	PTC 19.10 Part 10 & Method 19	PTC 19.10 Part 10 & Method 17

TABLE 7.1 STANDARD METHODS
(Continued)

Measurement Parameter	Sampling	Calibration	Analysis
(1) NO_x	JIS K 0104	JIS K 0104	JIS K 0104
(2) SO_2	JIS K 0103	JIS K 0103	JIS K 0103
(3) SO_3	NP[8]	NP	NP
(4) CO	JIS K 0098	JIS K 0098	JIS K 0098
(5) O_2	JIS B 7983	JIS B 7983	JIS B 7983
(6) HC	JIS B 7956	JIS B 7956	JIS B 7956
(7) DUST	JIS Z 8808	JIS Z 8808	JIS Z 8808

1. ASME Power Test Code
2. Fluid Meters, Their Theory and Application, ASME 1971
3. ASTM Standard Methods Part 26[5]
4. Code of Federal Regulations 40 CFR 60
5. Phase Discrimination Probe will be used.
6. See Test and Analytical Plan, Section 4.1
7. JIS Japanese Industry equivalent standard actually used.
8. NP = None Published in JIS

The equipment used to measure gas species is shown in Table 7.2. There were some problems with the gas measuring equipment. SO_2 was sampled through a phase descrimination probe design supplied by an EPA contractor. During the tests when limestone was added to the fuel, the phase discrimination probe as shown in Figure 7.1 plugged. This was the cause of the high SO_2 reductions measured in tests 11-15. It is thought that only a small amount of gas passed through the pluggage in the probe and in passing, a larger percentage of the SO_2 was captured by the sorbent. Additionally, the probe was cooled to about 15°C (59°F) to prevent it from burning out. This low temperature apparently condensed water from the flue gas which then caused the sample to act like a "wet scrubber". To correct the problem the phase discrimination probe was revised. The 1.1mm (0.04") gap ports was increased to 4.5mm (0.18") gap and the cooling water temperature was increased to 60°C (140°F) outlet temperature. These corrections resolved the problem and probe pluggage did not recur. The SO_2 concentration measurements during tests 11-15 are considered invalid and are not used in any analysis.

At the same time it was noticed that the HC sampling line was not heated as required by ASTM standards. A new sampling line was installed and the sampling line temperature was increased to 60°C (140°F). 60°C (140°F) was the operating temperature of the gas chromatograph tube and higher temperatures would damage the tube. The high sampling temperatures did increase the THC measured from 0.8 ppm during test 5 to 1.8 during the equivalent test Base-5. Because of the changes to the system and the increase in THC measured the THC data from tests 1-15 is considered invalid and is not used in any analysis of the data.

TABLE 7.2: SAMPLE TRAIN DESCRIPTION

Gas Species Sampled	SO_2
Extractive or In-situ	Extractive
Probe Temperature	60°C (140°F)
Probe material	Stainless Steel
Sample Line Material	Teflon
Sample Line Temperature Minimum	60°C (140°F)
Dryer (Type)	Electronic cooler
Filter (Type)	Quartz wool, mist eliminator for SO_3 then Teflon wool
Instrument Type or	Infrared non dispersive
Wet Chemical Method	
Manufacturer	Horiba
Precision	± 1% of full scale
Drift	± 2% of full scale
Range	0-5000 ppm
Span gas	3390 ppm SO_2
Zero gas	air
Measured During Test per Quality Assurance Plan	
Accuracy	54 ppm
Accuracy, %	1.6%
Precision	.029
Completeness, %	89.4%

TABLE 7.2: SAMPLE TRAIN DESCRIPTION

(Continued)

Gas Sampled	O_2
Extractive or In-situ	Extractive
Probe Temperature	15°C (59°F)
Probe material	Stainless Steel
Sample Line Material	Teflon
Sample Line Temperature Minimum	Ambient
Dryer (Type)	Electronic cooler
Filter (Type)	Glass wool, mist eliminator for SO_3
Instrument Type or Wet Chemical Method	Paramagnetic
Manufacturer	Horiba
Precision	± 1% of full scale
Drift	± 2% of full scale
Range	0-25%/0-5%
Span gas	air
Zero gas	N_2
Measured During Test per Quality Assurance Plan	
Accuracy %0_2	-.474
Accuracy, %	2.26
Precision	.0124
Completeness, %	100

TABLE 7.2: SAMPLE TRAIN DESCRIPTION
(Continued)

Gas Sampled	SO_3
Extractive or In-situ	Extractive
Probe Temperature	260°C (500°F)
Probe Material	Vycor
Sample Line Material	No sample line
Sample Line Temperature Minimum	
Dryer (Type)	No applicable
Filter (Type)	Glass wool
Instrument Type or	Spiral tube condensation Sodium Borate
Wet Chemical Method	
Measured During Test per Quality Assurance Plan	
Accuracy, ppm	*
Accuracy, %	*
Precision	*
Completeness, %	80%

*Not Available

TABLE 7.2: SAMPLE TRAIN DESCRIPTION
(Continued)

Gas Species Sampled	NO_x
Extractive or In-situ	Extractive
Probe Temperature	15°C (59°F)
Probe material	Stainless Steel
Sample Line Material	Teflon
Sample Line Temperature Minimum	Ambient
Dryer (Type)	Electronic cooler
Filter (Type)	Glass wool, then bubbler
Instrument Type or	Chemiluminescence with NO_2 - NO Converter
Wet Chemical Method	
Manufacturer	Shimadzu Seisakusho Ltd.
Precision	± 5% of full scale
Drift	± 2% of full scale
Range	0-100/500 ppm
Span gas	82.4 ppm NO
Zero gas	Air
Measured During Test per Quality Assurance Plan	
Accuracy, ppm	-2.32
Accuracy, %	2.81
Precision	.0133
Completeness %	100

TABLE 7.2: SAMPLE TRAIN DESCRIPTION
(Continued)

Gas Species Sampled	CO
Extractive or In-situ	Extractive
Probe Temperature	15°C (59°F)
Probe material	Stainless Steel
Sample Line Material	Teflon
Sample Line Temperature Minimum	Ambient
Dryer (Type)	Electronic cooler
Filter (Type)	Glass wool, mist eliminator for SO_3
Instrument Type or Wet Chemical Method	Non Dispersive Infrared
Manufacturer	Horiba
Precision	± 1% of full scale
Drift	± 2% of full scale
Range	0-1000 ppm
Span gas	494 ppm CO
Zero gas	Air
Measured During Test per Quality Assurance Plan	
Accuracy, ppm	-3.89
Accuracy, %	0.787
Precision	.010233
Completeness %	100

TABLE 7.2: SAMPLE TRAIN DESCRIPTION
(Continued)

Gas Species Sampled	Hydrocarbons
Extractive or In-situ	Extractive
Probe Temperature	60°C (140°F)
	Stainless Steel
Sample Line Material	Teflon
Sample Line Temperature Minimum	60°C (140°F)
Dryer (Type)	Sulfuric Acid
Filter (Type)	Glass wool,
Instrument Type or	Gas Chromtography with H_2 Flame Ionization Detector
Wet Chemical Method	
Manufacturer	Yanagimoto
Precision	± 1% of full scale
Range	0-50/50 ppm C
Carrier Gas	N_2 2.2 Kg/cm^2 H_2 1.2 Kg/cm^2 Air 2.0 Kg/cm^2
Span gas	45.4 ppm CH_4
Zero gas	N_2
Measured During Test per Quality Assurance Plan	
Accuracy, ppm	*
Accuracy, %	*
Precision	*
Completeness, %	82

*Not Available

USED FOR SAMPLING SO_2 IN THE PRESENCE OF REACTIVE LIMESTONE

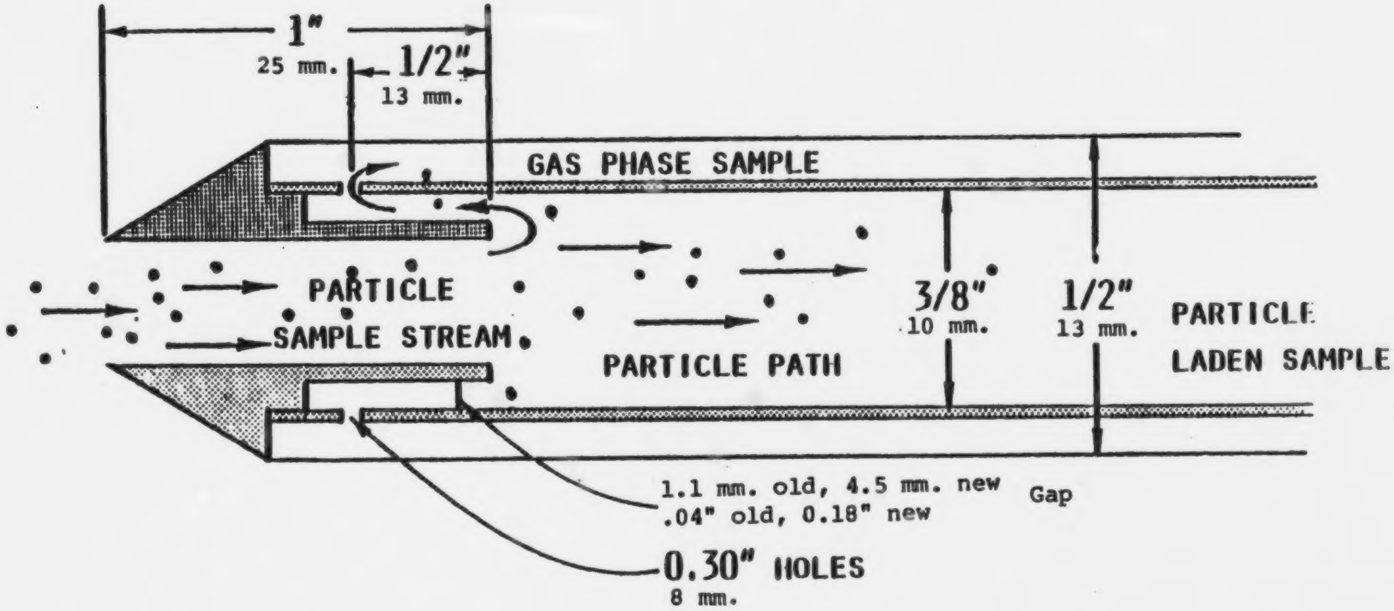
1"
25 mm.
1/2"
13 mm.
GAS PHASE SAMPLE
PARTICLE
SAMPLE STREAM
PARTICLE PATH
3/8"
10 mm.
1/2"
13 mm.
PARTICLE
LADEN SAMPLE
1.1 mm. old, 4.5 mm. new
.04" old, 0.18" new
Gap
0.30" HOLES
8 mm.

FIGURE 7.1: PHASE DISCRIMINATION PROBE

8.0 APPLICATION TO FULL SCALE

Considering the potential SO_2 reduction of 28% at 2.15 Ca/S mole ratio premixing limestone and coal in the pulverizer would not be appropriate for full scale application. Assuming a proportional increase in SO_2 reduction for a proportional increase in limestone added to the fuel the Ca/S mole ratio would have to be 3.8 to achieve 50% reduction in SO_2. This is well above the 50% reduction at a Ca/S ratio of 2.5 considered to be generally economical. Consequently, application to full scale is not recommended.

REFERENCES

1. Compilation of Air Pollutant Emission Factors (AP-42), Third Edition including supplements 1-13. U.S. Enviromental Protection Agency, Research Triangle Park, North Carolina, August 1982.

2. Yamane, T., Statistics An Introdoctory Analysis. Second Edition. Harper and Row, New York, 1967. Pages 389-405.

3. Verhoff, F. H. and Banchero, J. T., Predicting Dew Points of Flue Gases. Chemical Engineering Progress (Vol. 70 No. 8). August, 1974.

4. Maddalone, R., Laboratory and Field Evaluation of the Controlled Condensation System for SO_3 Measurements in Flue Gas Streams. Journal of the Air Pollution Control Association. Volume 29, Number 6. June 1979.

5. Annual Book of ASTM Standards. American Society for Testing and Materials, Philadelphia, Pennsylvania 1982.

APPENDIX A TEST RESULTS

All the raw data from IHI is contained in this appendix essentially as it was reported by IHI. Some of the data was adjusted for the purposes of consistency of reporting, the adjustments are described below.

Table A-1 Fuel Analysis

Table A-1 reports the fuel analysis for the whole test program. Sample 1 was taken from the coal containers at Port Elizabeth, New Jersey before it was shipped to Japan. The purpose of the sample was to have accurate information on the coal before the test program began. The remaining analyses are of samples taken at the beginning of each test day. Samples from the coal silo were taken as the coal entered the pulverizer and samples from the pulverized fuel storage bin were taken before the fuel entered the pneumatic transport system which delivered it to the burner and, depending on the test day, was an analysis of the coal and limestone mixture burned. IHI reported the fuel analyses on a surface moisture free basis, the analyses were corrected back to an "as received" basis by adding back in the surface moisture. This correction was made so that all the analyses represent the composition of the coal sampled, not a dried sample.

Table A-2 Limestone Analysis

The limestone samples were taken at the beginning of the test day and represent the limestone used in the first test of the day. The data was not adjusted and is as reported by IHI.

Table A-3 Fly Ash Analysis

Fly ash analysis is as reported by IHI. This data was taken to complete the mass balance for the system for tests 42 and 43, the 3 hour tests.

Table A-4 Fuel Ash Analysis

Fuel ash analysis was performed by Foster Wheeler on the sample taken before the coal was shipped. The data is as reported by Foster Wheeler's laboratory.

Table A-5 Heating Value of Sieved Pulverized Coal

Table A-6 represents the data as reported by IHI. This data was requested to ascertain the fineness of the limestone when it is pulverized with the coal.

Table A-6 Test Conditions and Results

The test results are as reported by IHI and the only adjustments made to the data is the presentation of the measured gas species in the as measured state and either corrected to 0% excess O_2 or to lb/10^6 Btu. The data was taken after at least a half hour at each condition, longer test periods were often required to insure that the system was operating at equilibrium.

TABLE A-1 FUEL ANALYSIS

Sample Date Sample Number Sample Location	1/20/83 1 1	4/25 105 2	4/25 201 3	4/26 107 2	4/27 202 3	5/6 110 2
Proximate						
Fixed Carbon, %	51.05	49.5	43.3	50.1	44.5	50.1
Volatile Matter, %	36.98	33.9	34.6	34.0	33.9	34.6
Ash, %	9.78	10.0	19.72	9.5	19.12	9.5
Moisture, %	2.19	6.6	2.4	6.4	2.5	5.9
Ultimate						
Carbon, %	72.65	67.4	60.9	67.8	61.7	68.7
Hydrogen, %	4.75	4.6	3.9	4.4	4.0	4.6
Oxygen, %	5.40	6.9	9.4	7.4	9.1	7.1
Nitrogen, %	1.37	1.2	1.1	1.2	1.1	1.2
Sulfur, %	3.86	3.3	2.6	3.3	2.5	3.1
HHV, Btu/lb.	12902	12617	10602	12761	10800	12818
Lab	FWDC	IHI	IHI	IHI	IHI	IHI

1. 1 is sample of shipped fuel; 2 is coal silo; 3 is pulverized fuel storage bin

NOTE: Samples 201, 202, 204, are analyses of the coal and limestone mixture actually fired.

TABLE A-1 FUEL ANALYSIS (Cont'd.)

Sample Date	5/11	5/12	5/13	5/16	5/16
Sample Number	111	204	112	114A	114B
Sample Location	2	3	2	2	2
Proximate					
Fixed Carbon, %	50.7	42.8	50.2	53.41	51.97
Volatile Matter, %	34.5	34.1	34.0	33.58	33.58
Ash, %	9.7	20.72	9.8	8.17	9.51
Moisture, %	5.1	2.4	6.0	4.84	4.94
Ultimate					
Carbon, %	68.9	60.7	68.1	70.74	69.20
Hydrogen, %	4.6	3.9	4.5	5.09	4.89
Oxygen, %	6.3	8.7	6.5	6.99	6.88
Nitrogen, %	1.3	1.1	1.3	1.41	1.36
Sulfur, %	4.1	2.5	3.8	2.74	3.22
HHV, Btu/lb.	12781	10548	12772	12607	12287
Lab	IHI	IHI	IHI	FWDC	FWDC

1. **1 is sample of shipped fuel; 2 is coal silo; 3 is pulverized fuel storage bin**

2. Note: Samples 201, 202, 204 are analyses of the coal limestone mixture actually fired.

TABLE A-2: LIMESTONE ANALYSIS

Sample Date Sample No. Location	4/25 303 1	5/6 307 1	5/12 309 1	4/26 315 1	5/16 311 1
$CaCO_3$,%	98.1	97.1	97.1	98.4	98.45
$MgCO_3$,%	0.9	0.69	0.62	0.66	1.26
SiO_2, %	0.11	0.12	0.04	0.28	nil
Al_2O_3, %	0.01	0.01	0.01	0.01	nil
Fe_2O_3, %	0.02	0.02	0.01	0.02	nil
Moisture, %					
Surface, %	0.03	0.04	0.06	0.04	
Inherent, %	0.1	0.1	0.2	0.1	
LAB	IHI	IHI	IHI	IHI	FWDC

1. Sample location is from weight belt at bottom of limestone silo that feeds the mill

TABLE A- 3 **FLY ASH ANALYSYS**

Sample Date Sample No. Sample Location Test No. Lab	5/16 42 1 42 IHI	5/16 43 1 43 IHI	5/16 43 1 43 FWDC
Ash Constituents, %			
SiO_2	28.9	11.7	12.3
Al_2O_3	16.3	7.75	7.8
Fe_2O_3	25.6	12.8	13.9
CaO	3.49	51.2	55.5
MgO	0.36	0.52	0.6
Na_2O	0.66	0.52	0.2
K_2O	1.06	1.07	0.6
SO_3	1.64	9.36	9.6
T_iO_2	0.05	0.04	0.2
P_2O_5	0.26	0.11	0.2

1. Ash conveyor at bottom of baghouse

TABLE A- 4

FUEL ASH ANALYSYS

Sample Date Sample No. Sample Location Test No. Lab	1/20/83 1 1 - FWDC	5/16 114A 2 42 FWDC	5/16 114B 2 42 FWDC
Ash Constituents, %			
SiO_2	31.7	34.8	32.4
Al_2O_3	20.2	22.5	20.4
Fe_2O_3	42.2	34.9	39.7
CaO	1.2	1.5	1.7
MgO	0.4	0.3	0.3
Na_2O	0.2	0.2	0.2
K_2O	1.2	1.4	1.4
SO_3	0.9	1.1	1.0
T_iC_2	1.0	1.0	0.9
P_2O_5	0.5	0.4	0.4

1. Sampled from truck shipping fuel to Port Elizabeth before it was shipped to Japan.
2. Coal Silo

TABLE A-5 HEATING VALUE OF SIEVED PULVERIZED COAL

Sample Date	4/18			5/25			5/26		
Sample No.	504			506			507		
Sample Location	1			1			1		
Measurement	Weight, %	% Moisture	Heating Value Btu/lb	Weight %	% Moisture	Heating Value Btu/lb	Weight %	% Moisture	Heating Value Btu/lb
Sieve Size									
50 Mesh	0	-	-	0	-	-	0	-	-
50 – 100	2.4	-	13717	1.9	-	13523	1.6	-	13450
100 – 200	23.6	2.8	13306	22.1	2.0	11143	20.4	2.2	11557
– 200	74.0	2.4	12657	76.0	2.2	10061	78.0	2.1	10331

1. Sampled at bottom of pulverized fuel storage bin.

TABLE A-6: TEST CONDITIONS AND RESULTS

Test No.	1	2	3	4	5
Date	4/15	4/15	4/15	4/15	4/16
OPERATING CONDITIONS (see Note)	2	2	2	2	2
Air to Coal Rate	1.9	1.876	1.893	1.90	1.916
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	0	0	0	0	0
Secondary Air Rate, Kg/h	13900	15700	15500	15600	14000
Primary Air Rate Kg/h	2850	2800	2840	2850	2874
OVERFIRE AIR, % TCA	19.7	20.5	22.4	1.3	0
FTR Method 1 } on/off	on	on	on	on	off
FTR Method 2	off	off	on	on	off
AMBIENT CONDITIONS					
Air Temperature, °C	23	23	21	20	21
Relative Humidity, %	63	64	68	70	50
Barometric Press. mbar[3]				1007.8	
FUEL FINENESS, % THROUGH 200 MESH[4]	79.2				77.2
AIR AND GAS TEMPERATURES					
Windbox Air, °C	292	299	284	300	215
Primary Air, °C	59	65	90	100	60
Air Heater Inlet °C[5]	435	450	460	465	430
Outlet °C[5]	220	225	250	262	210
Baghouse Outlet °C	157	178	200	220	185
Peak Flame Temperature Reduction, °C	67	37	137	87	0

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A- 6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	1 4/15	2 4/15	3 4/15	4 4/15	5 4/18
Gas Constituents at Air Heater Inlet					
O_2, %	3.2	3.1	3.2	2.9	3.0
SO_2, ppm	2703	2650	2597	2756	2809
SO_2, lb/10^6 Btu	5.19	5.06	4.99	5.21	5.34
SO_3, ppm	16.9	16.9	8.1	17.1	24.9
SO_3, ppm at 0% O_2	20	20	9.6	19.9	29.1
NO_x, ppm	170	190	152	255	220
NO_x, lb/10^6 Btu	.235	.261	.210	.346	.360
CO, ppm	70	40	50	30	20
CO, ppm at 0% O_2	83	47	59	35	23
HC Total, ppm	1.9[1]	1.5[1]	1.4[1]	1.2[1]	0.7[1]
HC Total, at 0% O_2	2.2[1]	1.8[1]	1.7[1]	1.4[1]	0.8[1]

[1] Data not valid due to equipment problems

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No. Date	6 4/18	7 4/18	8 4/18	9 4/18	10 4/18
OPERATING CONDITIONS (see Note)	2	2	2	2	2
Air to Coal Rate	1.916	1.916	1.916	1.9	1.927
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	0	0	0	0	0
Secondary Air Rate, Kg/h	14,000	13,600	13,600	15,200	16,200
Primary Air Rate Kg/h	2874	2874	2874	2850	2890
OVERFIRE AIR, % TCA	20.1	18.8	0	2.2	0
FTR Method 1 on/off	off	off	off	on	off
FTR Method 2 on/off	off	off	on	off	off
AMBIENT CONDITIONS					
Air Temperature, °C	21	21	20	18	18
Relative Humidity, %	50	51	56	60	65
Barometric Press. mbar[3]					1023.8
FUEL FINENESS, % THROUGH 200 MESH[4]					
AIR AND GAS TEMPERATURES					
Windbox Air, °C	215	185	270	305	310
Primary Air, °C	60	60	60	60	60
Air Heater Inlet °C[5]	435	440	455	450	460
Outlet °C[5]	215	215	234	230	236
Baghouse Outlet °C	190	195	205	207	216
Peak Flame Temperature Reduction, °C	77	47	97	37	-13

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A-6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	6 4/18	7 4/18	8 4/18	9 4/18	10 4/18
Gas Constituents at Air Heater Inlet					
O_2, %	3.0	3.0	3.0	2.8	5.0
SO_2, ppm	2650	2650	2650	2650	2385
SO_2, lb/10^6 Btu	5.04	5.04	5.04	4.98	5.10
SO_3, ppm	5.6	7.9	34.7	23.0	52.4
SO_3, ppm at 0% O_2	6.5	9.2	40.5	26.5	68.8
NO_x, ppm	175	175	250	240	310
NO_x, lb/10^6 Btu	.24	.24	.341	.325	.478
CO, ppm	100	120	25	25	20
CO, ppm at 0% O_2	210	140	29	29	26
HC Total, ppm	1.5[1]	1.4[1]	1.0	1.1	0.9
HC Total, at 0% O_2	1.8[1]	1.6[1]	1.2[1]	1.3[1]	1.2[1]

1. Data not valid due to equipment problems

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No.	11	12	13	Base 1	14
Date	4/19	4/19	4/19	4/25	4/25
OPERATING CONDITIONS (see Note)	2	2	2	2	2
Air to Coal Rate	1.9	1.91	1.907	1.907	1.907
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	330	330	330	330	330
Secondary Air Rate, Kg/h	14100	13200	16000	14200	14800
Primary Air Rate Kg/h	2850	2865	2860	2860	2860
OVERFIRE AIR, % TCA	0	19.9	0	2.9	1.1
FTR Method 1 } on/off	off	off	off	off	on
FTR Method 2	off	off	off	off	on
AMBIENT CONDITIONS					
Air Temperature, °C	22	21	20	26	25
Relative Humidity, %	77	75	75	40	40
Barometric Press. mbar[3]			1011.3		
FUEL FINENESS, % THROUGH 200 MESH[4]	78.0			76.48	
AIR AND GAS TEMPERATURES					
Windbox Air, °C	310	305	310	297	310
Primary Air, °C	60	60	60	65	85
Air Heater Inlet °C[5]	460	480	480	450	470
Outlet °C[5]	235	230	240	227	275
Baghouse Outlet °C	203	204	213	185	214
Peak Flame Temperature Reduction, °C	87	107	37	-	147

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A-6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	11 4/19	12 4/19	13 4/19	Base 1 4/25	14 4/25
Gas Constituents at Air Heater Inlet					
O_2, %	3.0	3.2	5.1	3.05	3.0
SO_2, ppm	1352[1]	1378[1]	1484[1]	1600[1]	1750[1]
SO_2, $lb/10^6$ Btu	2.57[1]	2.65[1]	3.2[1]	3.05[1]	3.33[1]
SO_3, ppm	6.8	6.5	9.6	-	-
SO_3, ppm at 0% O_2	8.0	7.7	12.7	-	-
NO_x, ppm	210	150	270	197	220
NO_x, $lb/10^6$ Btu	.239	.207	.419	.271	.300
CO, ppm	15	20	5	20	15
CO, ppm at 0% O_2	18	24	7	23	18
HC Total, ppm	0.8[1]	0.6[1]	0.3[1]	-	-
HC Total, at 0% O_2	0.9[1]	0.7[1]	0.4[1]	-	-

1. Data not valid due to equipment problems

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No. Date	15 4/25	16 4/26	17 4/26	18 4/26	19 4/26
OPERATING CONDITIONS (see Note)	6	6	6	6	6
Air to Coal Rate	1.907	1.907	1.907	1.913	2.023
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	330	330	330	330	330
Secondary Air Rate, Kg/h	14800	14600	14400	14200	15600
Primary Air Rate Kg/h	2860	2860	2870	2870	2790
OVERFIRE AIR, % TCA	0	20.6	18.5	19.3	1.1
FTR Method 1	on	on	on	on	on
on/off					
FTR Method 2	on	on	on	on	off
AMBIENT CONDITIONS					
Air Temperature, °C	25	22	22	22	22
Relative Humidity, %	40	63	64	67	67
Barometric Press. mbar^3	1021.7				
FUEL FINENESS, % THROUGH 200 MESH^4		79.2			
AIR AND GAS TEMPERATURES					
Windbox Air, °C	313	295	297	300	324
Primary Air, °C	85	72	74	74	80
Air Heater Inlet °C^5	470	485	480	485	480
Outlet °C^5	280	262	265	270	255
Baghouse Outlet °C	217	218	220	223	207
Peak Flame Temperature Reduction, °C	67	97	107	107	97

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE
6. Burner Parameters adjusted to measure effect on SO_2 capture.

TABLE A-6 (Continued) TEST CONDITIONS AND RESULTS

Test No.	15	16	17	18	19
Date	4/25	4/26	4/26	4/26	4/26
Gas Constituents at Air Heater Inlet					
O_2, %	2.9	3.0	3.0	2.9	2.8
SO_2, ppm	1250[1]	2000	1900	2000	2000
SO_2, lb/10^6 Btu	2.36[1]	3.80	3.61	3.78	3.76
SO_3, ppm	-	5.7	5.2	4.4	3.1
SO_3, ppm at 0% O_2	-	6.6	6.1	5.1	3.6
NO_x, ppm	250	150	160	160	230
NO_x, lb/10^6 Btu	.340	.205	.218	.218	312
CO, ppm	10	25	20	20	15
CO, ppm at 0% O_2	12	29	23	23	17
HC Total, ppm	-	2.9	4.5	4.6	3.2
HC Total, at 0% O_2	-	3.4	5.3	5.3	3.7

1. Data not valid due to equipment problems

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No. Date	20 4/26	Base-2 4/26	Base-3 4/28	21 4/28	22 4/28
OPERATING CONDITIONS (see Note)	2	1	1	2	2
Air to Coal Rate	1.893	2.023	1.91	1.89	1.91
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	330	330	330	330	330
Secondary Air Rate, Kg/h	16000	14900	14000	15600	15200
Primary Air Rate Kg/h	2840	3035	2860	2840	2870
OVERFIRE AIR, % TCA	0.5	0.6	2.4	22.2	20.5
FTR Method 1 } on/off	on	off	off	on	on
FTR Method 2	off	off	off	off	on
AMBIENT CONDITIONS					
Air Temperature, °C	22	22	26	26	24
Relative Humidity, %	68	67	60	60	65
Barometric Press. mbar^3		1020.4			
FUEL FINENESS, % THROUGH 200 MESH^4			77.28		
AIR AND GAS TEMPERATURES					
Windbox Air, °C	320	315	298	307	308
Primary Air, °C	85	80	63	75	95
Air Heater Inlet °C^5	470	470	435	455	470
Outlet °C^5	250	250	228	240	265
Baghouse Outlet °C	205	212	188	190	205
Peak Flame Temperature Reduction, °C	67	47	-	87	97

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A- 6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	20 4/26	Base 2 4/26	Base 3 4/28	21 4/28	22 4/28
Gas Constituents at Air Heater Inlet					
O_2, %	3.0	3.2	3.0	3.0	3.0
SO_2, ppm	1925	1950	2000	2000	2000
SO_2, lb/10^6 Btu	3.66	3.75	3.80	3.80	3.80
SO_3, ppm	3.7	-	-	3.4	3.8
SO_3, ppm at 0% O_2	4.3	-	-	4.0	4.4
NO_x, ppm	220	200	200	160	145
NO_x, lb/10^6 Btu	.300	.277	.274	.218	.199
CO, ppm	15	10	20	20	20
CO, ppm at 0% O_2	18	12	23	23	23
HC Total, ppm	3.4	3.4	-	3.1	5.0
HC Total, at 0% O_2	4.0	4.0	-	3.6	5.8

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No. Date	23 4/28	24 4/28	25 4/28	Base 4 5/6	26 5/6
OPERATING CONDITIONS (see Note)	2	2	2	1	2
Air to Coal Rate	1.92	1.943	1.913	1.907	1.907
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	330	330	330	330	330
Secondary Air Rate, Kg/h	14200	14700	14200	14600	17000
Primary Air Rate Kg/h	2880	2915	2870	2860	2860
OVERFIRE AIR, % TCA	20.5	4.0	19.9	1.1	3.5
FTR Method 1 on/off	off	off	off	off	off
FTR Method 2	on	on	off	off	on
AMBIENT CONDITIONS					
Air Temperature, °C	24	22	22	20	20
Relative Humidity, %	67	73	76	76	80
Barometric Press. mbar[3]			1014		
FUEL FINENESS, % THROUGH 200 MESH[4]				75.6	
AIR AND GAS TEMPERATURES					
Windbox Air, °C	305	310	320	295	305
Primary Air, °C	80	64	60	57	60
Air Heater Inlet °C[5]	460	465	460	455	475
Outlet °C[5]	260	262	250	225	265
Baghouse Outlet °C	210	210	214	200	229
Peak Flame Temperature Reduction, °C	97	77	57	17	-3

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A- 6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	23 4/28	24 4/28	25 4/28	Base 4 5/6	26 5/6
Gas Constituents at Air Heater Inlet					
O_2, %	3.0	3.0	3.0	3.0	5.0
SO_2, ppm	1950	2000	2000	2000	1600
SO_2, lb/10^6 Btu	3.71	3.8	3.8	3.8	3.42
SO_3, ppm	4.3	7.1	3.2	-	8.0
SO_3, ppm at 0% O_2	5.0	8.3	3.7	-	10.5
NO_x, ppm	140	200	125	225	400
NO_x, lb/10^6 Btu	.192	.274	.171	.307	.616
CO, ppm	20	18	70	10	0
CO, ppm at 0% O_2	23	21	82	12	0
HC Total, ppm	9.3	5.2	5.4	-	0.9
HC Total, at 0% O_2	10.9	6.1	6.3	-	1.2

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No.	27	28	29	Base 5	30
Date	5/6	5/6	5/6	5/11	5/11
OPERATING CONDITIONS (see Note)	2	2	2	1	2
Air to Coal Rate	1.907	1.907	1.902	1.902	1.902
Coal Rate, Kg/h	1500	1500	1125	1500	1500
Limestone Rate, Kg/h	330	330	248	0	0
Secondary Air Rate, Kg/h	17100	13600	10600	13800	13800
Primary Air Rate Kg/h	2860	2860	2140	2860	2860
OVERFIRE AIR, % TCA	19.5	25.5	1.6	2.4	2.4
FTR Method 1 on/off	off	off	off	off	off
FTR Method 2	off	off	off	off	off
AMBIENT CONDITIONS					
Air Temperature, °C	20	20	20	26	26
Relative Humidity, %	80	80	80	32	36
Barometric Press. mbar[3]			1008.7		
FUEL FINENESS, % THROUGH 200 MESH[4]				77.4	
AIR AND GAS TEMPERATURES					
Windbox Air, °C	325	315	310	303	303
Primary Air, °C	60	60	60	63	65
Air Heater Inlet °C[5]	475	470	400	425	435
Outlet °C[5]	255	238	225	230	233
Baghouse Outlet °C	225	208	177	188	193
Peak Flame Temperature Reduction, °C	-33	17	67	0	0

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A-6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	27 5/6	28 5/6	29 5/6	Base 5 5/11	30 5/11
Gas Constituents at Air Heater Inlet					
O_2, %	5.3	3.0	3.0	3.0	3.0
SO_2, ppm	1800	2200	2000	2675	2750
SO_2, lb/10^6 Btu	3.93	4.18	3.8	5.08	5.23
SO_3, ppm	8.0	5.8	2.3	25.3	24.1
SO_3, ppm at 0% O_2	10.7	6.8	2.7	29.5	28.2
NO_x, ppm	190	135	185	230	260
NO_x, lb/10^6 Btu	.299	.184	.253	.315	.356
CO, ppm	5	30	20	40	40
CO, ppm at 0% O_2	7	35	23	47	47
HC Total, ppm	2.4	3.4	3.6	1.5	3.7
HC Total, at 0% O_2	3.2	4.0	4.2	1.8	4.3

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No. Date	31 5/11	32 5/11	33 5/11	Base 6 5/12	34 5/12
OPERATING CONDITIONS (see Note)	2	2	2	2	2
Air to Coal Rate	1.907	1.907	1.907	1.907	1.907
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	0	0	0	330	330
Secondary Air Rate, Kg/h	15900	15300	13500	13600	13600
Primary Air Rate Kg/h	2860	2860	2860	2860	2860
OVERFIRE AIR, % TCA	0.5	3.9	1.2	0	0.6
FTR Method 1 } on/off	off	on	off	off	off
FTR Method 2 } on/off	off	off	on	off	off
AMBIENT CONDITIONS					
Air Temperature, °C	26	23	22	28	28
Relative Humidity, %	41	53	54	44	46
Barometric Press. mbar[3]			1014.5		
FUEL FINENESS, % THROUGH 200 MESH[4]				78.12	
AIR AND GAS TEMPERATURES					
Windbox Air, °C	310	310	285	298	310
Primary Air, °C	65	75	65	65	65
Air Heater Inlet °C[5]	458	455	465	435	455
Outlet °C[5]	240	240	245	230	240
Baghouse Outlet °C	206	200	205	189	197
Peak Flame Temperature Reduction, °C	-43	27	-13	47	7

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A- 6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	31 5/11	32 5/11	33 5/11	Base 6 5/12	34 5/12
Gas Constituents at Air Heater Inlet					
O_2, %	4.8	3.0	3.0	3.0	2.9
SO_2, ppm	2380	2625	2600	2000	2100
SO_2, lb/10^6 Btu	5.03	4.99	4.94	3.80	3.97
SO_3, ppm	53.6	34.7	29.9	-	6.9
SO_3, ppm at 0% O_2	69.6	40.5	34.9	-	8.0
NO_x, ppm	340	250	250	200	212
NO_x, lb/10^6 Btu	.517	.341	.274	.289	309
CO, ppm	10	20	20	0	0
CO, ppm at 0% O_2	13	23	23	0	0
HC Total, ppm	9.8	8.4	8.4	-	1.4
HC Total, at 0% O_2	12.7	9.8	9.8	-	1.6

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No. Date	35 5/12	36 5/12	37 5/12	38 5/12	39 5/12
OPERATING CONDITIONS (see Note)	6	6	2	2	2
Air to Coal Rate	1.907	1.907	1.907	1.907	1.907
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	330	330	330	330	330
Secondary Air Rate, Kg/h	14000	14300	16800	15200	14200
Primary Air Rate Kg/h	2860	2860	2860	2860	2860
OVERFIRE AIR, % TCA	1.8	0.6	3.1	5.6	1.3
FTR Method 1 on/off	off	off	off	off	off
FTR Method 2	off	off	off	off	on
AMBIENT CONDITIONS					
Air Temperature, °C	28	28	28	28	25.5
Relative Humidity, %	44	44	44	48	50
Barometric Press. mbar[3]					1008.8
FUEL FINENESS, % THROUGH 200 MESH[4]					
AIR AND GAS TEMPERATURES					
Windbox Air, °C	312	312	320	325	304
Primary Air, °C	65	65	66	72	66
Air Heater Inlet °C[5]	455	455	470	470	470
Outlet °C[5]	242	242	255	254	265
Baghouse Outlet °C	202	204	217	212	222
Peak Flame Temperature Reduction, °C	-13	-3	-13	37	-3

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE
6. Burner Parameters adjusted to measure effect on SO_2 capture

TABLE A-6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	35 5/12	36 5/12	37 5/12	38 5/12	39 5/12
Gas Constituents at Air Heater Inlet					
O_2, %	3.0	3.0	5.2	3.0	3.2
SO_2, ppm	2150	2100	1750	2000	1970
SO_2, lb/10^6 Btu	4.09	3.99	3.79	3.80	3.79
SO_3, ppm	-	-	12.8	6.9	9.1
SO_3,ppm at 0% O_2	-	-	17.1	8.1	10.8
NO_x, ppm	225	283	310	210	265
NO_x, lb/10^6 Btu	.309	.387	.483	.287	.366
CO, ppm	-	0	0	0	0
CO, ppm at 0% O_2	0	0	0	0	0
HC Total, ppm	-	-	2.2	2.3	2.3
HC Total, at 0% O_2	-	-	2.9	2.7	2.7

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No. Date	Base 7 5/13	40 5/13	41 5/13	42 5/16	42 5/16
OPERATING CONDITIONS (see Note)	1	2	2	2	2
Air to Coal Rate	1.907	1.913	1.913	1.907	1.907
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	500	500	500	0	0
Secondary Air Rate, Kg/h	14000	15100	15900	13200	13700
Primary Air Rate Kg/h	2860	2870	2870	2860	2860
OVERFIRE AIR, % TCA	0	0.6	3.2	19.9	20.5
FTR Method 1 on/off	off	off	off	off	off
FTR Method 2 on/off	off	off	off	on	on
AMBIENT CONDITIONS					
Air Temperature, °C	26.8	26.2	27.5	21	21.5
Relative Humidity, %	50.5	50	50	85	87
Barometric Press. mbar[3]			1003.9		
FUEL FINENESS, % THROUGH 200 MESH[4]	74.2			76.6	
AIR AND GAS TEMPERATURES					
Windbox Air, °C	347	315	338	285	280
Primary Air, °C	63	62	63	60	62
Air Heater Inlet °C[5]	480	460	470	550	460
Outlet °C[5]	265	243	260	245	240
Baghouse Outlet °C	216	212	212	200	200
Peak Flame Temperature Reduction, °C	-13	27	-13	57	37

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A- 6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	Base 7 5/13	40 5/13	41 5/13	42 5/16	42 5/16
Gas Constituents at Air Heater Inlet					
O_2, %	3.0	2.9	4.0	2.9	3.0
SO_2, ppm	1750	1750	1775	2665	2525
SO_2, lb/10^6 Btu	3.33	3.31	3.57	5.04	4.80
SO_3, ppm	-	6.3	7.8	7.0	11.9
SO_3, ppm at 0% O_2	-	7.3	9.6	8.1	13.9
NO_x, ppm	205	200	225	140	150
NO_x, lb/10^6 Btu	.280	.272	.326	.190	.205
CO, ppm	0	0	0	150	75
CO, ppm at 0% O_2	0	0	0	174	88
HC Total, ppm	-	1.3	1.9	2.0	1.7
HC Total, at 0% O_2	-	1.5	2.3	2.3	2.0

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No. Date	42 5/16	42 5/16	42 5/16	43 5/16	43 5/16
OPERATING CONDITIONS (see Note)	2	2	2	2	2
Air to Coal Rate	1.907	1.907	1.916	1.89	1.89
Coal Rate, Kg/h	1500	1500	1500	1500	1500
Limestone Rate, Kg/h	0	0	0	330	330
Secondary Air Rate, Kg/h	14000	13800	13700	13500	13500
Primary Air Rate Kg/h	2860	2860	2874	2835	2850
OVERFIRE AIR, % TCA	20.2	20.4	19.9	19.0	20.2
FTR Method 1 } on/off	off	off	off	off	off
FTR Method 2 }	on	on	on	on	on
AMBIENT CONDITIONS					
Air Temperature, °C	22	21.5	22	19.5	17.5
Relative Humidity, %	85	85	85	75	78
Barometric Press. mbar^3			995.2		
FUEL FINENESS, % THROUGH 200 MESH^4				75.32	
AIR AND GAS TEMPERATURES					
Windbox Air, °C	285	287	287	300	307
Primary Air, °C	61	61	60	60	58
Air Heater Inlet °C^5	460	460	480	480	490
Outlet °C^5	242	245	243	256	264
Baghouse Outlet °C	203	204	207	183	186
Peak Flame Temperature Reduction, °C	47	47	37	17	17

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A-6 (Continued) TEST CONDITIONS AND RESULTS

Test No. Date	42 5/16	42 5/16	42 5/16	43 5/16	43 5/16
Gas Constituents at Air Heater Inlet					
O_2, %	3.3	3.2	3.0	2.9	3.0
SO_2, ppm	2450	2500	2375	1850	1875
SO_2, lb/10^6 Btu	4.74	4.81	4.51	3.50	3.56
SO_3, ppm	18.7	20.9	19.4	6.8	6.6
SO_3, ppm at 0% O_2	22.2	24.7	22.7	7.9	7.7
NO_x, ppm	155	155	155	150	150
NO_x, lb/10^6 Btu	.215	.214	.212	.176	.205
CO, ppm	70	65	65	20	20
CO, ppm at 0% O_2	83	77	76	23	23
HC Total, ppm	1.4	2.2	2.6	1.3	1.2
HC Total, at 0% O_2	1.7	2.6	3.0	1.5	1.4

TABLE A-6 (continued): TEST CONDITIONS AND RESULTS

Test No.	43	43			
Date	5/16	5/16			
OPERATING CONDITIONS (see Note)	2	2			
Air to Coal Rate	1.90	1.89			
Coal Rate, Kg/h	1500	1500			
Limestone Rate, Kg/h	330	330			
Secondary Air Rate, Kg/h	13700	13400			
Primary Air Rate Kg/h	2850	2835			
OVERFIRE AIR, % TCA	20.5	19.7			
FTR Method 1 } on/off	off	off			
FTR Method 2	on	on			
AMBIENT CONDITIONS					
Air Temperature, °C	16	15			
Relative Humidity, %	79	76			
Barometric Press. mbar[3]		995.2			
FUEL FINENESS, % THROUGH 200 MESH[4]					
AIR AND GAS TEMPERATURES					
Windbox Air, °C	318	320			
Primary Air, °C	58	60			
Air Heater Inlet °C[5]	493	490			
Outlet °C[5]	270	275			
Baghouse Outlet °C	192	193			
Peak Flame Temperature Reduction, °C	67	37			

1. Outer Register Set at Baseline Condition
2. Outer Register Set at Optimum Condition
3. Measured once a day at end of last test
4. Measured once a day at beginning of first test
5. GAS TEMPERATURE

TABLE A-6 (Continued) TEST CONDITIONS AND RESULTS

Test No.	43	43
Date	5/16	5/16
Gas Constituents at Air Heater Inlet		
O_2, %	3.4	3.0
SO_2, ppm	1775	1950
SO_2, lb/10^6 Btu	3.45	3.79
SO_3, ppm	7.7	7.7
SO_3, ppm at 0% O_2	9.2	9.2
NO_x, ppm	140	160
NO_x, lb/10^6 Btu	.196	.187
CO, ppm	20	20
CO, ppm at 0% O_2	24	24
HC Total, ppm	1.1	2.3
HC Total, at 0% O_2	1.3	2.7

APPENDIX B COAL AND SORBENT SELECTION

Foster Wheeler's recommendation to EPA was to test coal and limestone combinations that would be most likely to be used by midwestern and eastern boiler owners. A high sulfur eastern or midwestern coal and an eastern or midwestern limestone. The complete analysis and recommendation is contained in the following report. After reviewing FW's recommendations and its own internal recommendations, the EPA decided to use the same limestone that was being used by other contractors doing similar work. This would allow comparison of results between test programs. Based on this reasoning the VICRON limestone was chosen for the test series. The recommendation to use an eastern or midwestern high sulfur coal was accepted by the EPA and the middle Kittanging coal was chosen.

INVESTIGATION OF COAL AND SORBENTS FOR EPA PROJECT "EVALUATION OF SULFUR CAPTURE CAPABILITY OF A PROTOTYPE SCALE CONTROLLED FLOW/SPLIT-FLAME BURNER"

Prepared by

E. S. Schindler and J. Vatsky

Contract No. 68-02-3906

FWEC No. 2-43-4454

January 26, 1983

1.0 INTRODUCTION

The proper selection of a coal and sorbent for the test program "Evaluation of Sulfur Capture Capability of a Prototype Scale Controlled Flow/ Split-flame Burner" is based on a balance of the future commercial application of the technology and the past experimental work. Future commercial applications of the technology require an evaluation of user location with respect to fuel and sorbent availability. Past experimental work requires that an experimental continuity exists between researchers so that the work can be compared on the same basis and that the new work build on the information and experiences of the past. The coals and sorbents recommended in this paper are based on this balance. The commercial aspects are considered in more detail than by previous evaluations because of FWEC's familiarity with them. We feel that the commercial considerations should be reviewed periodically during the development of any new technology.

The choice of coal was based on field experience with coals used in boilers in the 500 to 1000 MW size range and located east of the Mississippi River where the technology will be of most interest to the boiler operator. The choice of sorbent was based on a review of the historical literature listed in the bibliography and on conversations with other individuals knowledgable in the use of calcium based sorbents at Foster Wheeler, EPA and EERC. Recent results from EPA-sponsored programs were reviewed with the latter and the information thus obtained was considered.

2.0 COAL RECOMMENDATIONS

Listed in Table 1 are the coals that could be used in the test program. Each coal is being used at a large utility power station and is typical of the high sulfur fuels in use today.

Table 2 shows coals that have been used in recent EPA combustion testing. The first three have been used at EERC in the EPA's LWS test furnace to evaluate the DMB concept burner. The fourth fuel is being used at WIPCO.

A Pittsburgh coal is the most highly recommended coal of the group for pilot testing for the following reasons:

1. It is a high sulfur eastern bituminous coal used typically in the eastern U. S., and represents a large fraction of the coal types that impact on high SO_2 ambient levels and acid rain.

   This technology will have its highest cost/benefit ratio if used with high sulfur coals on eastern or midwestern boilers. It provides a low cost per ton of SO_2 removed and would help the eastern coal fields to remain competitive.

2. It is similar to the Indiana coal used at EERC.

3. Eastern high sulfur coals are currently the most under-utilized resource in this country. It would allow a simple technology to be used on currently unregulated boilers, i.e., less than 250 million Btu input industrial boilers. It would also allow boilers built in 1971 to 1979 era without FGD systems to use a higher sulfur coal (most likely an eastern bituminous coal) while maintaining SO_2 emissions below 1.2 lb/million Btu.

   A low sulfur eastern coal would not be acceptable because of its low sulfur content. These fuels are already in high demand for this reason.

The midwestern coals would be recommended as highly as the eastern coals except that they have higher inland transportation costs and would add to the cost of the experiment.

The western coals are not as suitable for initial testing. They are generally very low in sulfur and have the least impact on acid rain and ambient SO_2 in the east. LIMB may provide the potential to meet current NSPS of 70% SO_2 control with low sulfur coals.

The most highly recommended fuel is the fuel with the least tendency to slag. Slagging fuel could potentially cause problems with the test furnace.

Although no problem is expected in getting the highest rated fuel, the next rated fuel will be purchased in its place if there is an availability problem. If the specific coal cannot be purchased, an equivalent fuel of low slagging potential will be chosen for the testing.

TABLE B-1

RECOMMENDED COALS FOR LIMB TESTING AT IHI

FUEL	1	2	3	4	5	*
RATING	2	5	4	3	1	
PROXIMATE, %	AS REC'D	AS REC'D	AS REC'D	AS REC'D	AS REC'D	AS REC'D
Moisture	3.18	2.78	3.17	4.3	9.32	7.5
Volatiles	37.64	25.03	36.94	38.13	33.5	32.1
Fixed Carbon	44.55	49.13	49.16	43.79	42.71	43.6
Ash	13.62	23.01	10.73	13.78	14.47	16.74
ULTIMATE, %						
Sulfur	3.87	2.08	2.58	4.43	4.36	3.24
H_2	5.11	3.27	5.43	4.66	5.39	4.07
C	65.25	66.01	70.65	69.33	61.97	62.35
N_2	0.83	.92	0.82	1.17	1.00	1.02
O_2	8.14	4.05	6.62	6.01	12.81	5.08
HHV, BTU/lb	12173	11322	12809	11972	11430	11500
Mineral Analysis, %						
Fe_2O_3	31	15.87	14.5	24.7	27.5	
Na_2O	1.1	.34	0.7	0.1	1.2	
K_2O	0.8	2.91	2.1	1.3	1.1	
Ash Fusion, °F Red**	2100	2100	2100	2180	2100	

* Fuel Listed in Proposal

** H = W

TABLE B-2: FUELS USED IN CURRENT EPA COMBUSTION RESEARCH

	EERC			
Characteristic	Utah	Indiana	Illinois	WIPCO Pearl Station
Proximate, %				
Moisture	2.84	5.75	16.89	12.80
Ash	7.22	11.15	9.37	11.89
Volatiles	41.95	36.47	35.64	34.32
Fixed Carbon	47.99	46.63	38.10	40.99
Ultimate, %				
Moisture	2.84	5.75	16.89	12.80
Carbon	71.70	64.91	57.85	61.40
Hydrogen	5.63	4.34	4.09	4.55
Nitrogen	1.46	1.37	1.03	0.89
Sulfur	0.85	2.41	3.30	3.36
Ash	7.22	11.15	9.37	11.89
Oxygen	10.30	9.57	7.47	5.41
HHV	12,731	11,527	10,480	10,773

3.0 CHOICE OF SORBENT

The choice of sorbent should be based on two criteria: the sorbent should be the most efficient in terms of sulfur captured per mole of calcium and it should have some historical use in sulfur capture. The best sorbent will have a balance of these two criteria.

The candidates for sorbent selection are the following: Limestone, $CaCO_3$; Calcium Hydroxide, $Ca(OH)_2$; Lime, CaO. Each of these three choices include the choice of dolomite or calcite.

Discussions were held with the EPA and EERC and their comments and suggestions are included in this document. The only solid recommendation made by them was the Vicron material which has commercial availability problems. Solid data was not available for an eastern or midwestern limestone relative to in-situ SO_2 control.

Dolomite vs. Calcite Limestone

The reactivity of dolomite vs. high calcium limestone has been studied, both experimentally and theoretically. Experimentally, it has been shown in pilot tests that dolomites can be as reactive as high calcium limestone, but thermodynamically it has been shown that at the high injection temperature expected (2,000°F) $MgSO_4$ cannot form. At lower temperatures (1400°F) it can form but the reaction rates are much slower and the product formed is insignificant at the residence times expected in this temperature regime. This is a very controversial area. Many researchers feel a significant amount of $MgSO_4$ is formed in the 1400°F range. Magnesium in the dolomite may create conditions where a $CaSO_4$ shield is not formed over the particle surface. With a diffusion path into the center of the particle sulfation can continue utilizing much of the calcium but none of the magnesium.

The dolomites may have higher calcium utilization but the calcites have more calcium. If the MgO does not absorb SO_2, then more dolomite would be required to capture the same amount of SO_2. The increase would depend on the amount of magnesium contained in the dolomite. The extra dolomite required could add a substantial amount to the operating cost of the system.

Limestone/$Ca(OH)_2$/Lime

The choice of limestone, $Ca(OH)_2$ or lime has also been studied extensively in the literature with pilot LIMB testing both domestically and in Europe. In summary, the SO_2 absorption capacity is essentially the same for limestone and $Ca(OH)_2$ and slightly lower for lime, but the maximum absorption occurs at different temperatures. TVA reported in 1973 that maximum SO_2 absorption for limestone can be $752^{o}F$ higher than the maximum for $Ca(OH)_2$ or lime (2732 vs. 2102). Other researchers, such as Potter, 1969 showed a 500 degree difference with a limestone maximum at around $2000^{o}F$.

Since calcination is a time temperature related reaction, a perfectly calcined lime would then be dead burned or at least over calcined when injected into the furnace. Over calcination is known to reduce reactivity of the lime particle; hence, the lime would immediately start over burning upon injection. A hydrate or a limestone in contrast would reach a temperature plateau during the calcination step as the H_2O or CO_2 is exfoliated from the lime, after which the temperature would rise. The limestone would require either a longer time or a higher temperature for the calcination to be complete, since limestone requires roughly twice the energy of the hydrate to calcine. Hence, the limestone could sustain a higher or longer time-temperature period without deactivation. This higher time or temperature would be very important in minimizing deactivation as the limestone is passing through the peak temperature regime of the flame. Limestone appears to be the preferred sorbent over $Ca(OH)_2$ from a cost view-

TABLE B-3 RECOMMENDED LIMESTONES FOR LIMB TESTING AT IHI

NAME	GROVE	COLOMBIA	GREER	VICRON	FREDONIA UPPER	MICHIGAN* MARL
BCR No.**	1359	2203			2061	2129
Rating	1	2	4	6	5	3
COMPOSITION, %						
$CaCO_3$	95.3	96	80.4	97.0	98.2	78.2
$Mg\ CO_3$	1.32	3.57	3.5	1.6	.72	4.8
SiO_2	.77	0.2	10.34	1.0	.82	7.6
Al_2O_3	.25	0.01	3.18	0.15	.09	1.2
Fe_2O_3	.09	0.17	1.24	0.05	0.1	.6
H_2O	2.10	1.75		0.2		
Other		1.5	.39			7.6
Na_2O	.03	.05	.23		.02	
K_2O	.06	.01	.72		.1	

* Reconstituted from a lime analysis

** Bituminous Coal Research Number

point, although some LIMB tests indicate higher SO_2 capture with $Ca(OH)_2$.

Limestone Choice

Table 2 shows the most acceptable choices of limestone that have been found. Each one has its advantages and disadvantages.

Vicron

Vicron has shown that it is a good choice for SO_2 absorption. The testing at EERC has shown that high utilizations can be achieved. But it has one disadvantage - it is not located near the potential customers of the limestone. The high shipping cost to the midwest would be unacceptable to these utilities. The cost-effective commercial application of this process would depend on a number of midwestern or eastern sources of limestone, and to prove the process with the highest cost limestone would be less than optimum for the utilities. The process should be proven with midwestern or eastern limestones for it to be most commercially viable.

Fredonia and Michigan Marl

TVA tested numerous limestones in the late sixties for their Shawnee test program. This process has some similarities to the LIMB process. Their testing has shown that the Fredonia upper ledge and the Michigan Marl were the best limestones. The Michigan Marl is frankly not available in the large quantities necessary for a large power plant, and as such is not acceptable. The Fredonia upper ledge is a reasonable choice (although it is high in potassium, a potential problem(, but there is one disadvantage - the quarry will not select only upper ledge limestone. The quarry blends upper, lower, and blue ledges into a composite and only sells the composite. Although it may be possible to negotiate a strict specification for only the upper ledge, this would be a long, drawn out affair and, in fact, may not be successful.

Greer Limestone

Greer limestone is a product Foster Wheeler has extensive experience with in fluid bed boilers, and has shown itself to be highly reactive. It has one disadvantage for the LIMB process - it is high in sodium and potassium. Sodium and potassium have been linked with a sensitivity to higher temperatures and the consequent deactivation of the calcite. Although this presents no problem with fluid bed systems where the temperature is maintained well below any critical point (the potassium and sodium may be advantageous in a fluid bed application in that it may increase the utilization at the low temperatures) it could reduce the utilization of calcium when used in the LIMB process, as well as cause fouling of convection surfaces and radiant superheaters in field units.

Grove and Columbia

The Grove limestone has been extensively studied and has shown some resistance to deactivation at higher temperatures. It is also very low in sodium and potassium. It is a midwestern limestone with the only disadvantage being that it has not been tested in a LIMB type process. Of course, very few limestones have been tested in a LIMB process. It is recommended by FW internal specialists as a good candidate for the LIMB process. It is well known, heavily studied, and readily available and appears to be the optimal candidate. A limestone with similar characteristics is 2203 from Colombia Quarry, Ill., and would be acceptable as an alternate.

4.0 BIBLIOGRAPHY

Attig, R. C. "Pilot Plant Investigation of the Potential of Direct Limestone-Dolomite Additive Injection for Control of Sulfur Dioxide from Combustion Flue Gases," EPA report APTD 1485 (NTIS No. PB184049), December 1968.

Bituminous Coal Research, Inc. "Research on Methods for Control of Sulfur Dioxide Emissions from Coal Burning Power Boilers", BCR Report L-273 to Electric Research Council & National Coal Association, March 7, 1968.

Borgwardt, Robert H., "Kinetics of the Reaction of SO_2 with Calcined Limestone", Environmental Science & Technology, Vol. 4, No. 1, January 1970.

Case, Patricia, Energy and Environmental Resources Co., Irvine, Ca., Personal Interview, January 5, 1983.

Coutant, R. W., et al "Investigation of the Reactivity of Limestone and Dolomite for Capturing SO_2 from Flue Gas," EPA report APTD 0802 (NTIS No. PB204385), October 1971.

Coutant, R. W., R. E. Barrett and E. H. Lougher, "SO_2 Pickup by Limestone and Dolomite Particles in Flue Gas", Journal of Engineering for Power, April 1970.

Drehmel, Dennis, U.S. Environmental Protection Agency, Research Triangle Park, N.C. Personal Interview, January 5, 1983.

Duwel, Ludwig, Karl-Wilhelm Buhne and Hans Lahann "Investigation of the Capture of Ash and Sulfur for Brown Coal Firing of Steam Generators", Braunkohle, n. 9, Sept. 1972, p. 297-310.

Goldschmidt, K., "Experiments for Removal of Sulphur Dioxide from Flue Gases", Institut fur Verfahrenstechnik und Dampfkesselwesen der Universitat Stuttgart. 1967.

Hartman, Miloslav and Robert W. Coughlin, "Reaction of Sulfur Dioxide with Limestone and the Grain Model", AIChE Journal, Vol. 22, No. 3, May 1976.

Hartman, Miloslav, and Robert W. Coughlin, "Reaction of Sulfur Dioxide with Limestone and the Influence of Pore Structure", Ind. Eng. Chem., Process Des. Develop., Vol. 13, No. 3, 1974.

Hubble, B. R., Stanley Siegel, L. H. Fuchs, H. R. Hoekstra, B. Tani and P. T. Cunningham, "The Formation of $Mg_3Ca(SO_4)$ during the Sulfation Reaction of Dolomite", Journal of the Air Pollution Control Association, Vol. 27, No. 4, April 1977.

Reid, William T. "Basic Factors in the Capture of Sulfur Dioxide by Limestone and Dolomite", Journal of Engineering for Power, January 1970.

Potter, Allen E., "Sulfur Oxide Capacity of Limestone", Ceramic Bulletin, Vol. 48, No. 9, 1969.

Ramachandran, P. A. and J. M. Smith, "A Single-Pore Model for Gas-Solid Noncatalytic Reactions", AIChE Journal, Vol. 23, No. 3, May 1977.

Schwartz, S. H. and R. N. Salzman, "Experimental Investigation of the Penetration and Dispersion Phenomena in the Limestone Injection Method", EPA report APTD1134 (NTIS PB210256), April 1971.

Slack, A. V., and H. L. Falkenberry "Sulfur Dioxide Removal from Power Plant Stack Gas by Limestone Injection", Transactions of the ASME, January 1970.

Snyder, Robert B., W. Ira Wilson, Irving Johnson, and Albert A. Jonke, "Synthetic SO_2 Sorbents for Fluidized-Bed Coal Combustors", Journal of the Air Pollution Control Association, Vol. 27, No. 10, October 1977.

Sohn, H. Y. and K. Rajamani "Successive Gas-Solid Reactions in a Porous Pellet: Application to the Reaction of Metal Sulfides in the Presence of Lime", Chemical Engineering Science, Vol. 32, pp. 1093-1101, 1977.

Stewart, Robert. Foster Wheeler Boiler Corp., Livingston, N.J., Personal Interview, January 4, 1983.

Taylor, Thomas, Foster Wheeler Development Corporation, Livingston, N.J., Personal Interview, December 2, 1982.

Tennessee Valley Authority "Sulfur Oxide Removal from Power Plant Stack Gas: Investigation of the Reactivities of Limestone to Remove SO_2 from Flue Gas," EPA report APTD0699 (NTIS PB202407), 1971.

Tennessee Valley Authority "Full-Scale Desulfurization of Stack Gas by Dry Limestone Injection," Vol. I EPA -650/2-73-019a (NTIS PB228447), August 1973.

Tennessee Valley Authority "Sulfur Oxide Removal from Power Plant Stack Gas: Conceptual Design and Cost Study. Sorption by Limestone or Lime Dry Process," EPA report APTD1275 (NTIS PB178972), 1968.

Wen, C. Y. and M. Ishida, "Reaction Rate of Sulfur Dioxide with Particles Containing Calcium Oxide", Environmental Science & Technology, Vol. 7, No. 8, August 1973

Yang, Ralph T., C. R. Krishna and M. Steinberg "Fluidized-Bed Coal Combustion with Lime Additives. The Phenomenon of Peaking of Sulfur Retention at a Certain Temperature", Ind. Eng. Chem., Fundam. Vol. 16, No. 4, 1977.

Zentgraf, Karl-Martin "Supplement to the Contribution on SO_2 Measurements in Flue Gases and on Flue Gas Desulfurization with Compounds of Alkaline Earth Metals", Chemical Translation Service, Knoxville, Tenn. 1967.

Section No. 0
Revision No. 0
Date: 3/8/83
Page 1 of 1

QUALITY ASSURANCE PLAN FOR THE PROJECT "EVALUATION OF SULFUR CAPTURE CAPABILITY OF A PROTOTYPE SCALE CONTROLLED FLOW SPLIT FLAME BURNER"

EPA CONTRACT NO. 68-02-3906

FWEC NO. 2-43-4454

Approvals: Joel Vatsky
Joel Vatsky
FW Project Manager
Date: 3/16/83

Edmund Schindler
Edmund Schindler
FW Quality Assurance Officer
Date: 3/16/83

Charles C Masser
Charles Masser
EPA Project Officer
Date: 4/5/83

Judith S Ford
Judy Ford
EPA Quality Assurance Officer
Date: 4-4-83

1.0 TABLE OF CONTENTS AND INTRODUCTION

1.1 Table of Contents

	Quality Assurance Plan Components	Pages	Section No.	Rev.	Date
1.	Title Page	1	0.0	0	3/8/83
2.	Table of Contents	2	1.0	0	3/8/83
3.	Project Description	2	2.0	0	3/8/83
4.	Project Organization	2	3.0	0	3/8/83
5.	Quality Assurance Objectives	3	4.0	0	3/8/83
6.	Sampling Procedures	5	5.0	0	3/8/83
7.	Sample Custody	3	6.0	0	3/8/83
8.	Calibration Procedures and Frequency	5	5.0	0	3/8/83
9.	Analytical Procedures	5	5.0	0	3/8/83
10.	Data Reduction, Validation and Reporting	3	7.0	0	3/8/83
11.	Internal Quality Control Checks and Frequency	1	8.0	0	3/8/83
12.	Performance and System Audits and Frequency	2	9.0	0	3/8/83
13.	Preventative Maintenance Procedures and Schedules	1	10.0	0	3/8/83
14.	Specific Routine Procedure to be Used to Assess Attainment of QA Objectives for Measurement Data	2	11.0	0	3/8/83
15.	Corrective Action	1	12.0	0	3/8/83
16.	Quality Assurance Reports to Management	1	13.0	0	3/8/83
	Revisions to Test Plan		APPENDIX		

1.2 Persons Receiving Official Copies of this Plan and any subsequent revisions:

(1) FWEC Quality Assurance Project Officer (Acting) and Project Engineer, Edmund Schindler

(1) FWEC Project Manager, Joel Vatsky

(6) EPA Project Officer, Charles Masser

(1) EPA Contract Officer, William Caviness

(1) EPA Quality Assurance Officer, Judith Ford

1.3 INTRODUCTION

This document is the Quality Assurance Plan (QAP) for the EPA Contract 68-02-3906. It is a part of the Test and Analytical Plan (TAP) submitted on December 2, 1982. Some parts of this plan are covered in the TAP and are referenced directly rather than duplicated herein. Direct references are also made to recognized standards published by American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME) and the U. S. Environmental Protection Agency. Because of the wide distribution and use of these Standards they are not duplicated in this document. They are referenced directly by their chapter number, standard number or method number as appropriate to each organization.

2.0 PROJECT DESCRIPTION

The Test and Analytical Plan describes the project in detail, but a short description is provided. The project is to test and evaluate the SO_2 capture capability of sorbent injection through a low NO_x coal burner with internal staging. The burner, made by Foster Wheeler Energy Corp. (FWEC), is an advanced commercial design of the type used in large coal fired public utility and industrial boilers. In these large boilers SO_2 capture is typically achieved through the use of flue gas scrubbers at a substantial cost. This program will test the efficacy of a technology that will achieve ends similar to the scrubber system but at substantially reduced costs. The burner is capable of producing a split flame with controlled flow and variable velocity and uses proprietary flame temperature control methods. The activity of this project will be to vary the operating parameters and flame temperature control methods to optimize SO_2 capture and then report on the results of the tests. The SO_2 is captured by its reaction with a sorbent; in this case limestone is used as a sorbent. The testing will occur at a pilot boiler facility at FWEC's Japanese Licensee, Ishikawajima Harima Heavy Industries, Inc. (IHI) in AIOI, Japan.

Running a test program in Japan presents some problems in developing a QA plan. The ability to communicate is restricted to middle management personnel in IHI, who must then translate the instructions to his peers or subordinates. Communication is via Telex or special courier mail and is, therefore, time consuming. When FWEC has run a test program like this in the past only the test conditions are Telexed. IhI then develops an organized detailed test plan for their operators.

A FWEC Project Engineer observes the testing and evaluates the data on site but communicates only through IHI's project engineer. The data is measured on Japanese instruments with Japanese instruction manuals and recorded on Japanese data sheets. Therefore, much of the QA information is not available to an English speaking person. Standard operating procedures, internal quality control audits, etc. would all have to be translated into English.

This plan then is written as if the testing is to take place at FW. Upon arrival in Japan the QA officer will correct the QA plan based on his observations and discussions with the personnel at IHI. Standard methods will be verified or deviations noted, internal IHI procedures will be described as best as possible. Standard Forms and records will be copied for insertion into the final QA Plan after the testing is over. The QA officer in essence will act as an independent laboratory auditor. Of course, any material proprietary to FW or IHI will be recorded but will not appear in the final report.

The burner being used in Japan was developed with test programs in the U. S. on a small industrial boiler, but the final stages of its development occurred at this pilot plant in Japan. The two data sets showed the same NO_x emissions when corrected for the different fuels and furnaces. When this burner was scaled up and tested on a larger utility boiler the burner performed in a similar manner, correcting for fuel and furnace differences. What this implies is that the testing done at IHI was validated as being representative of a full scale boiler and comparable to another "pilot plant" (small industrial boiler) in the U. S.

3.0 PROJECT ORGANIZATION

The organizational chart, Figure 3.1, shows the relationship between FWEC and IHI. Edmund Schindler, the Project Engineer, is responsible for designing the test program and directing the day to day testing. After each day's testing he will evaluate the results and make changes for the next day's testing as needed. The prime contact at IHI is H. Ikebe, Manager, Combustion Engineering Department. He directs the overall project in Japan. Because of the cultural and language problems present in this project, FW will act through him to direct the day to day operation of the project. Mr. Ikebe will also act as the QA officer in Japan. He is one of the project managers who directs research at the pilot plant from time to time and has the authority to make changes in the internal Quality Assurance program. He is the QA officer at IHI for this project.

The small size of this program and the relative independence of the FW Project Engineer from IHI will allow the Project Engineer to act as a QA Auditor for the laboratory.

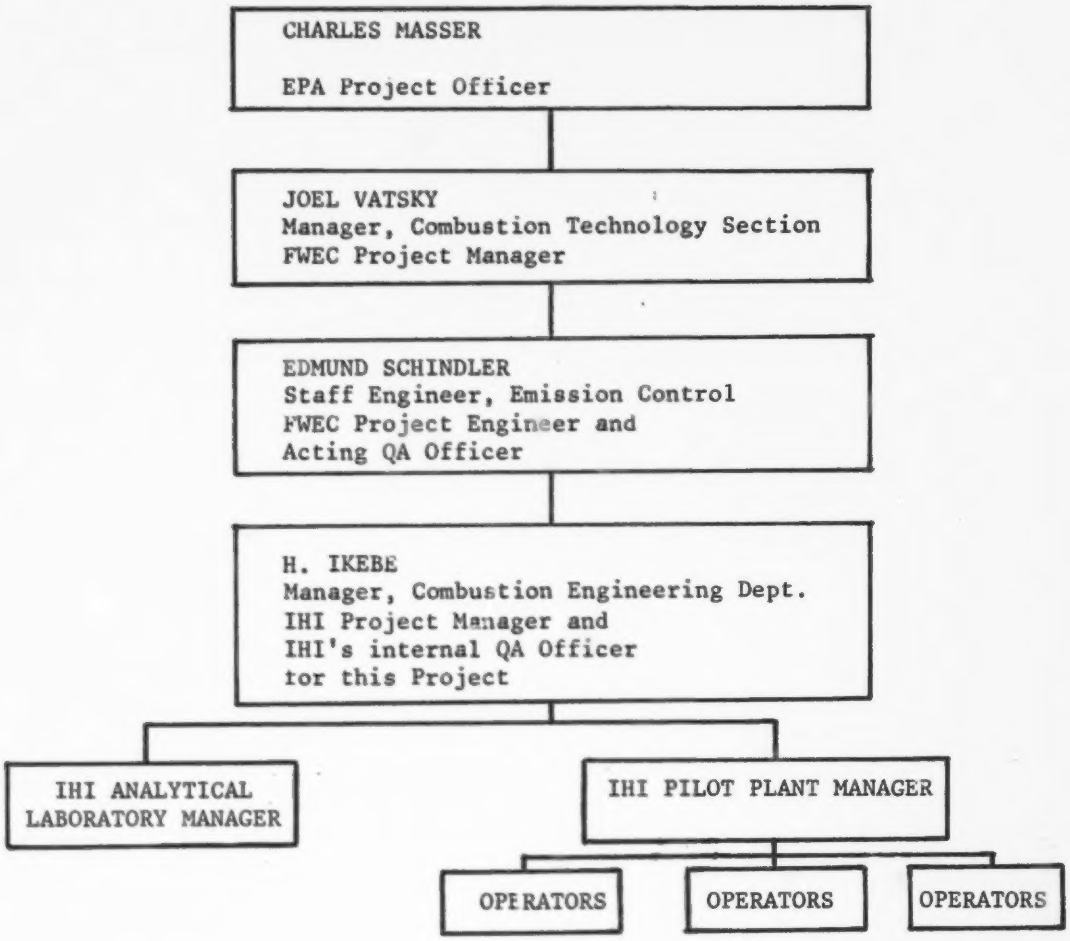
CHARLES MASSER
EPA Project Officer
JOEL VATSKY
Manager, Combustion Technology Section
FWEC Project Manager
EDMUND SCHINDLER
Staff Engineer, Emission Control
FWEC Project Engineer and
Acting QA Officer
H. IKEBE
Manager, Combustion Engineering Dept.
IHI Project Manager and
IHI's internal QA Officer
for this Project
IHI ANALYTICAL LABORATORY MANAGER
IHI PILOT PLANT MANAGER
OPERATORS
OPERATORS
OPERATORS

Figure 3.1 Organizational Chart

4.0 QUALITY ASSURANCE OBJECTIVES FOR MEASUREMENT DATA IN TERMS OF PRECISION, ACCURACY, COMPLETENESS, REPRESENTATIVENESS AND COMPARABILITY

The QA objectives for measurement data in terms of precision, accuracy and completeness are shown in Table 4.1. They are based on published values in the references shown using the methods listed in Section 5.0. These methods are all normally used in determining the performance of a boiler, its emission characteristics or the efficiency of a control device.

There are only two methods shown that are new and not totally developed or contain a slight variation. The first one involves SO_x measurement. The SO_x measurement method uses a phase discrimination probe that was developed under an EPA project, at Energy and Environmental Research Corp., EERC, during testing of sulfur capture with limestone. This probe is different than the standard method shown in ASME PTC 19.10 Para. 3.03.4.2.5. The difference is primarily that the new probe can easily be added to a Method 5 type sampling system while the old method cannot.

The second method involves the use of the elemental analysis of coal ash for analysis of limestone. Typically, limestone would be analyzed using ASTM C-25. This method would be fine except that the ash will be analyzed using ASTM D 3682. Since ASTM D 3682 could also be used for analyzing the limestone in the ash, more consistent data can be obtained if the same method is used for both. Additionally, the limestone will be added to the coal before combustion and technically will actually be "coal ash."

TABLE 4.1 QUALITY ASSURANCE OBJECTIVES

Measurement Parameter (Method)	Reference	Experimental Conditions	Precision Std. Dev.	Accuracy	Completeness
Combustion Air Flows (Venturi)	PTC 4.1		± 0.35%[1]	± 0.35%[1]	95%
Air Temperature (I.D. Fan Inlet) Thermocouples	PTC 4.1		± 0.5%[1]	± 0.5%[1]	95%
Relative Humidity (Hygrometer)	ASTM E 337		± 4%[1]	± 4%[1]	95%
Barometric Pressure (Mercury Barometer)	ASTM D 3631		± 10 Pa	± 20 Pa	95%
Flame Temperature (Optical Pyrometer)	PTC Part 3 Chapter 7		± 15°F	± 30°F	95%
Coal and Limestone Finess (Standard ~~Screens~~)	ASTM D 197		± 2%[1]	± 4%[1]	95%
Air and Gas Temperatures (Thermocouples)	PTC 4.1		± 0.5%[1]	± 0.5%[1]	95%
NO_x (Chemiluminescense)	PTC 19.10 Part 10		± 0.5%[1]	± 1.0%[1]	95%
SO_2 (Non Dispersive Infra-red)	PTC 19.10 Part 10		± 1%[1]	± 2%[1]	95%
SO_3 (Wet Chemical)	PTC 19.10 Part 10		None Published	None Published	90%
CO (Non-Dispersive Infra-red)	PTC 19.10 Part 10		± 1%[1]	± 2%[1]	95%
O_2 (Paramagnetic)	PTC 19.10 Part 10		± 1.5%[1]	± 1.5%[1]	95%
HC (Non-Dispersive Infra-red)	PTC 19.10 Part 10		± 1%[1]	± 2%[1]	95%

Measurement Parameter (Method)	Reference	Experimental Conditions	Precision Std. Dev.	Accuracy	Completeness
Coal Analysis (Ultimate & Proximate)	D 3176		See Table 3	in D 3176	95%
Bottom, Fly Ash and Limestone (Elemental)	D 3682		See Table 1 in	D 3682	95%
Coal and Limestone Rate (Gravimetric feeder)	PTC 19.5 Chapter 1		0.1%[1]	± 0.5%[1]	95%

Notes: 1 These objectives are a percentage of full span of the meter reading.

5.0 SAMPLING, CALIBRATION AND ANALYTICAL PROCEDURES

Sampling, calibration and analysis of the measurement parameters are all accomplished by standard methods, except one: burner register calibration. The standard methods shown in Table 5.1 are the methods normally used in the U. S. to make the various measurements. It is not expected that all of the methods shown will be the ones used at the pilot plant in Japan; deviations from the methods shown will be recorded in the bound notebook. If Japanese standards equivalent to the methods shown in Table 5.1 are actually used, then Table 5.1 will be corrected to show the actual methods used.

The only deviation from the standard methods shown will be the use of the phase discrimination probe. This probe is used for removing reactive particulates from the gas being sampled as it is being sampled. The probe is shown in Figure 5.1. The removal of reactive particulates from the sampling stream before it enters the sampling line is most important. Normal methods require a filter. The filter would collect the lime which would absorb the SO_2 or SO_3 being sampled. The filter would act like a packed bed. Although a small filter will be required to protect the instruments it will not build up a bed of lime as fast with the phase discrimination probe and hence less SO_2 will be absorbed. Any liquid condensers, scrubbers, or any liquid systems in the sampling line will be avoided completely. The calibration of the SO_2 instrument will be performed such that the bias caused by the filter can be measured with a typical amount of material on it. A similar bias measurement will be made for the SO_3 system.

TABLE 5.1 STANDARD METHODS

Measurement Parameter	Sampling	Calibration	Analysis
Combustion Air Flow	PTC 19.5[1] Chapter 4	Fluid Meters[2]	PTC 19.5 Chapter 4
Ambient Conditions			
Temperature (ID Fan Inlet)	PTC 19.3 Part 3 Chapter 3	PTC 19.3 Part 3	PTC 19.3 Part 3
Relative Humidity	E 337[3]	E 337	E 337
Barometric Pressure	D 3631[3]	D 3631	D 3631
Flame Temperature	PTC 19.3 Part 3	PTC 19.3 Part 3	PTC 19.3 Part 3
Coal and Limestone Fineness	D 197	D 197	D 197 D 431
Combustion Air & Gas Temperature	PTC 19.3 Part 3 Chapter 3	PTC 19.3	PTC 19.3
Flue Gas Species	PTC 19.10 Part 10 & Method 19[4,5]	PTC 19.10 Part 10 & Method 19	PTC 19.10 Part 10 & Method 19
Coal Analysis Ultimate, Proximate and HHV	D 2234	D 3172-79 D 3286	D 3172-79[6] D 3286
Limestone and Ash Analysis	D 2234	D 3682	D 3682
Coal and Limestone Rate	PTC 19.5 Chapter 1	PTC 19.5 Chapter 1	PTC 19.5 Chapter 1

1. ASME Power Test Code
2. Fluid Meters, Their Theory and Application, ASME 1971
3. ASTM Standard Methods Part 26
4. Code of Federal Regulations 40 CFR 60
5. Phase Discrimination Probe will be used.
6. See Test and Analytical Plan, Section 4.1

USED FOR SAMPLING SO_2 IN THE PRESENCE OF REACTIVE LIMESTONE

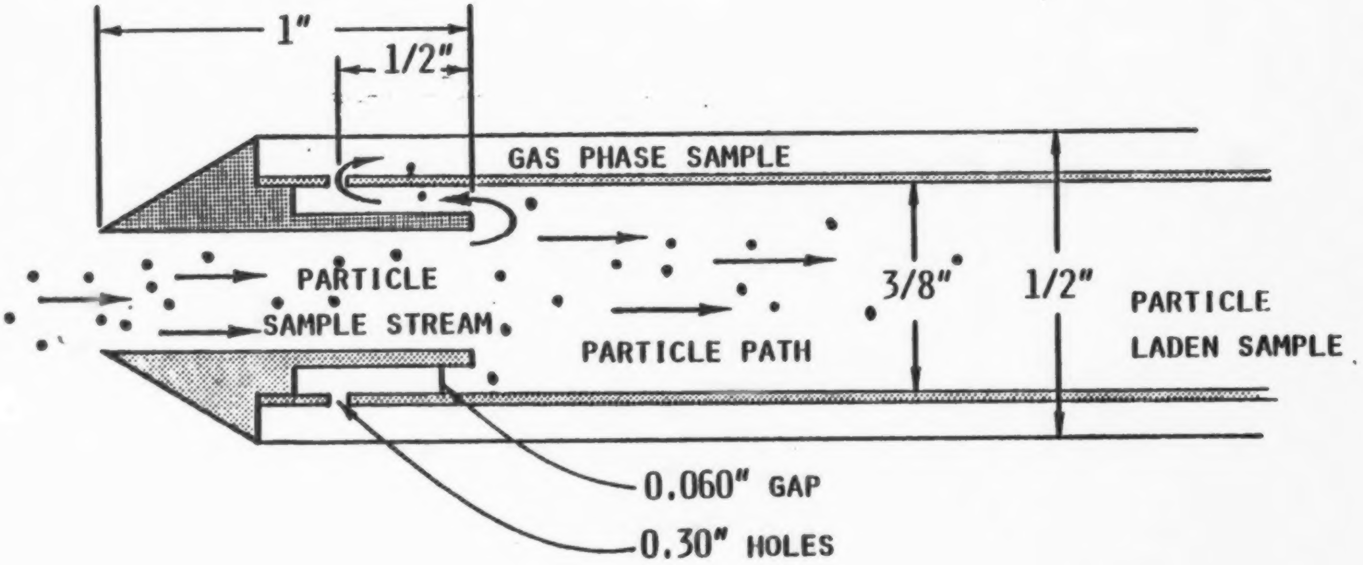
1"
1/2"
GAS PHASE SAMPLE
PARTICLE
SAMPLE STREAM
PARTICLE PATH
3/8"
1/2"
PARTICLE
LADEN SAMPLE
0.060" GAP
0.30" HOLES

FIGURE 5.1 PHASE DISCRIMINATION PROBE

5.1 Standard Method for Calibrating Burner Register Position and Backlash

Burner registers are driven by manual or motor operated drives that must operate through universal joints and bull ring gear sets. The mechanical backlash in these systems can be substantial because of the limitations of the operating environment. The high temperatures and test conditions require loose mechanical coupling to minimize binding.

Burner register setting readings are taken from either a percent open or degrees open indicator on the outside of the windbox. The mechanical backlash in the system allows the indicator to be moved without moving the register blades.

The registers must be calibrated when the boiler is not operating. One person located inside the windbox must measure the perpendicular distance from one blade to the next, while another person outside the windbox must operate the register drive and set the indicator at 0, 25, 50, 75 and 100 open position. This test must be performed in both directions opening and closing the register drives. The perpendicular measurement between register blades can easily be converted to degrees open using basic trigonometry and the distance between blade bearings as follows:

x = perpendicular distance from the tip of one blade to the side of the next blade

d = distance between bearings of adjacent blades

A = angle of blades

$$\sin(A) = \frac{x}{d}$$

$$A = \text{inverse sine } \frac{x}{d}$$

When changing the burner register position the operator must be sure to turn past the backlash and record the indicator position and the direction he was turning to achieve the indicated setting. The calibration charts then can be used to determine the exact register setting.

6.0 SAMPLE CUSTODY

Coal, limestone, bottom ash flyash samples, SO_3 wet reagents are the only materials that will not be measured when the sample is taken; they require sample custody procedures. Most of these samples will be analyzed in-house at IHI laboratory on site at AIOI. In these situations the samples will be labeled and hand carried every day to the laboratory for analysis. Each sample will have a form similar to Figure 6.1 attached to it except the form will be in Japanese. In this case we cannot make a form up for IHI because of the language problems but the form in Figure 6.1 will be compared to their form for their review and any serious inconsistencies between their form and the one in Figure 6.1 will be corrected. Sample forms of those used at the laboratory for labeling and field and lab tracking will be collected and presented in the final report. The Project Engineer on site during the testing will review the field and lab tracking reports and report his findings of their procedures in the final report.

Samples of coal will be taken that will not be analyzed immediately. These will be stored pending an analysis of the variability of the coal and its impact on the results. If required, these may be shipped to FW for analysis; in that case dual language labels will be used and the samples will be logged in using the form in Figure 6.2.

FOSTER WHEELER ENERGY CORP.

Sample Description ______________________________

____

Plant: ______________________ Location ______________

Date: ______________________________

Time ______________________________

Coal:	Pulverized Crushed Bottom	Limestone	Raw Pulverized
Ash:	Fly		

Sampled by: ______________________________

Sample I.D. ______________________________

Remarks: ______________________________

____

____

____

FIGURE 6.1 General Sample Label

FOSTER WHEELER ENERGY CORPORATION

SAMPLE TRACKING FORM

Field Sample No.	Description	Date Received	Received by	Analysis Required	Analysis Received Date

FIGURE 6.2 Sample of Sample Tracking Form for Samples Shipped from Japan

7.0 DATA REDUCTION, VALIDATION, AND REPORTING

7.1 Data Reduction Scheme

Emissions data, SO_2 and NO_x will be reduced accoring to Method 19 in Appendix A of Federal Regulations 40 CFR Part 60. All other data is collected to support validation of the process conditions under which the SO_2 capture efficiency was measured. This data will be reported as measured.

7.2 Principle Validation Criteria

The test will be validated through the process conditions measured and the fuel and limestone analysis. The first criteria used to validate a test will be the process conditions measured. The primary criteria used will be a ratio of the total combustion air as measured by the venturis and the stoichiometry of combustion as measured by the excess oxygen. This is one indicator of coal variability. The Student's t-test will be used to evaluate the hypothesis that the measured value equals the known value. The known value will be based on the ultimate analysis of the coal. This analysis is currently being performed on a sample of the coal shipped. The Students t-test is described in Appendix J of the EPA's IERL/RTP QA/QC Manual.

One of the main problems is the inability to measure the sulfur content of the coal being burned. Samples of the coal will be taken twice a day, but only one sample every other day will be analyzed. The results of the coal analyses will only be available after the testing is over so the variability will not be known until after the tests are over. If, after the testing is over, it is found there is significant variability in the coal sulfur content, then the remaining sample will be analyzed and the sulfur content of the nearest coal sample will be used to estimate the SO_2 content in the furnace. Coal with high variability will be defined using Chi-Square test defined in Appendix J of the EPA's IERL/RTP QA/QC Manual. The expected standard deviation of the coal sulfur content is 0.45; the test will be done at the 95% level of significance. The expected standard deviation was determined from 40 samples of coal taken at WIPCo, Pearl Station, EPA Contract No. 68-02-3127 from 8/20/81 to 10/13/81 (unstaged testing). The WIPCo project uses a coal that is similar in sulfur content.

The third method of validating the tests will be the use of a baseline test that will be run at the beginning of each day. The baseline test is described in the Test and Analytical Plan (TAP), Section 3.2. The baseline test will be run at whatever CA/S mole ratio the pilot plant is set up for on that day as described in the revision to the TAP Appendix A. This will result in the following baseline tests:

Ca/S Mole Ratio	Number of Baseline Tests
2.0	5
0.0	3
1.0	1
3.0	1

The variability of the baseline tests will be compared to the variability of the actual coal sulfur content using the Chi-Squared test.

The SO_2 reduction of the baseline test will be correlated with the Ca/S mole ratio; the standard error of estimate will be used for the variability of the baseline tests.

7.3 Criteria for Data Integrity During Collection and Reporting of Data

The data integrity during collection and reporting will be validated strictly on the use of standard forms, neatness, handling of forms after they are filled, neatness and completeness of maintenance and calibration logs and the neatness and quality of construction of the laboratory. Any evaluation beyond this would be limited by the language and cultural problems. The QA officer will keep a bound note book to evaluate the Data Integrity in it. All QA calculations for validation will be recorded.

8.0 INTERNAL QUALITY CONTROL CHECKS

Limestone, coal and ash samples will be split when taken. Half the sample will be analyzed at IHI's lab, the other half will be preserved until after the final report has been approved. Samples are preserved in air-tight polyethylene bags. At least two of the split samples preserved and analyzed at IHI will be analyzed at FWEC as an Internal QA check.

Zero and span gas checks of the calibration of each continuous gas measuring device will be completed at the beginning of each day. Only gases with traceable standards will be used. When the standard gas cylinder pressure drops below 200 psig a new cylinder will be connected. The old and new cylinders will be checked against each other for reading within 3 standard deviations of the expected results.

The gas and air flows, coal flow rate, excess oxygen, coal analysis, and feed water flow rate can be checked against each other using a heat and energy mass balance. These process conditions should remain stable over the whole test program or change in an expected manner. A change in one will affect at least one other measurement conversely. The failure or bias of one instrument will not show up as a change in another.

These internal quality control checks are methods normally used during boiler performance tests by all boiler manufacturers. Other internal QC checks will be evaluated on site during the testing.

9.0 PERFORMANCE AND SYSTEMS AUDITS

9.1 Internal Audits

A review of IHI's internal audit procedure will be made when the Project Engineer will be on site to supervise the test program. This review will consist of an interview with the pilot plant manager where the last and next internal audit will be evaluated. Because of the language problems a review of the results of the internal audits will not be made except as discussed in the interview. The pilot plant will be evaluated using ASTM Standard D 3614 "Evaluating Laboratories Engaged in Sampling and Analysis of Atmospheres and Emissions".

A report of the interview will be written and included in the Quality Assurance section of the Final Report.

12.2 External Audits

Any external audits by Japanese ministries equivalent to the U.S. E.P.A. will be discussed during the interview and the results will be reported on; primarily the previous test programs at IHI by FW will be used to evaluate overall performance of the pilot plant.

The results of previous test programs will be compared to this program as the tests proceed to ensure that all systems react as expected. Any systems not reacting as expected will be pointed out and testing will stop to evaluate the system for correct performance. Selected results of previous test programs will be published in the Final Report (in accordance with contract guidelines) and compared for consistency of results.

10.1 PREVENTATIVE MEASURES

The IHI pilot plant at AIOI is at the primary manufacturing site of IHI boilers. This means that if any part should fail and it can be made in the shops, it will be given highest priority in fabrication. Our own experience last time we tested at IHI was with a failed burner part; the part was repaired overnight and operational the next morning. Not only are the shops available but the maintenance area of the shops with their stockroom of parts to keep the shops operational is available to the pilot plant.

A fully staffed maintenance division which tends to the equipment in the shops also tends to the equipment in the pilot plant. Operating hours of each major piece of equipment is logged and normal maintenance is scheduled based on the projected life left in the equipment. A list of the spare parts available in the maintenance division would be a major undertaking.

In summary, this pilot plant is fully incorporated into a major manufacturing facility where most of the pilot plant was made. It is not a small, isolated facility or located at headquarters far from the main manufacturing site.

11.0 SPECIFIC ROUTINE PROCEDURES TO BE USED TO ASSES ATTAINMENT OF QA OBJECTIVES FOR MEASUREMENT DATA

Precision, accuracy, and completeness will be used to asses data quality on a routine basis. The precision and accuracy of each continuous gas measuring device will be determined by measuring a calibration gas. The concentration of the calibration gas will be selected to be as close as possible to the average expected reading during the test program.

The calibration gas concentration will be used to test instrument span. This test will occur daily. After each span check the precision and accuracy will be updated. If the precision or accuracy exceed the value required for corrective action as described in Section 15, the instrument will be checked for problems. Any problems found will be corrected. If the correction affects the instrument calibration, it will be recalibrated.

11.1 Accuracy

Accuracy is defined as the average difference between the measured value and the actual value. Often this is called "bias". It is calculated as follows:

$$A = X - \sum_{i=1}^{n} x_i/n$$

n = number of measurements
X = concentration of span gas
x_i = concentration of measurement i
A = accuracy

11.2 Precision

Precision is defined as the "Within Laboratory Standard Deviation". This definition describes the average precision of all operators running each piece of equipment. In order to compare the precision of each measurement system the Relative Standard Deviation will be used. It is calculated as follows:

$$S_R = \frac{S}{X} 100\%$$

S_R = Relative Standard Deviation

S = standard deviation of sample

$\overline{X}$ = mean of sample

$$\overline{X} = \sum_{i=1}^{n} x_i/n$$

$$s = \left(\sum_{i=1}^{n}(x_i \ \bar{x})^2/(n-1) \right)^{1/2}$$

11.3 Completeness

Completeness is defined as the ratio of valid measurement to planned measurements and can be calculated as follows:

$$C = 1 - \frac{n_v}{n_p}$$

C = completeness

n_v = valid measurements

n_p = planned measurements

12.0 CORRECTIVE ACTION

The corrective action threshold is defined by the Student's t-test. When the span gas measurement is considered different from the listed value of the zero or span gas using the t-test the zero and span will be adjusted to their traceable values. If adjustment cannot be achieved, corrective action shall be taken.

The corrective action taken at this point would include a leak check and check on the span gas. If these do not correct the problem then a more complete check on the system is required. The instrument check procedure in the owner's manual will be used. If the instrument is operating correctly it should be recalibrated,if not overhauled.

Instruments that measure process conditions will read almost a constant value, since most of the tests are at the same conditions. A change in the process conditions will likely affect a number of process measurements; a change in one without a change in the other will create a suspicion in the operator and precipitate an action to investigate. This method requires fully trained and experienced operators of the equipment who know what to expect from the equipment.

IHI's internal procedures for corrective action are not known. The responsible persons for initiating corrective action include the instrument operator, FW QA officer, and IHI Project Manager. Approval for corrective action is obtained from the Pilot Plant Manager.

13.0 QUALITY ASSURANCE REPORTS TO MANAGEMENT

The internal Quality Assurance reporting procedures at IHI are not known to Foster Wheeler, hence a description of same cannot be made. Foster Wheeler's internal Quality Assurance report to management concerning the IHI test facility has been informal elevations of past testing at IHI based on observations at the Pilot Plant by FW engineers.

For this program the QA report to management will consist of this QA plan. The information collected at IHI as part of this plan and the analysis of it is the Final Report to EPA.